Final Report for:

NJ Storm Hardening Recommendations and Review/Comment on EDC Major Storm Response Filings

Submitted to:
State of NJ, Board of Public Utilities, Office of Clean Energy;
Center for Energy, Economic and Environmental Policy,
Bloustein School, Rutgers, The State University of New Jersey

GE Energy Consulting

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Legal Notices

Foreword

This document was prepared by General Electric International, Inc. (GEII) through its Energy Consulting group (EC) based in Schenectady, NY. It is submitted to The State of NJ, Board of Public Utilities, Office of Clean Energy (OCE) and the Center for Energy, Economic and Environmental Policy (CEEEP), Bloustein School of Planning and Public Policy, Rutgers University. Questions and any correspondence concerning this document should be referred to:

TECHNICAL

Lavelle A, Freeman

Manager, Transmission and Distribution

GE Energy Management Energy Consulting
General Electric International, Inc.
1 River Road
Building 53, Room 314
Schenectady, NY 12345 USA

Phone: (518) 385-3335

Fax: (518) 385-9529

lavelle.Freeman@ge.com

COMMERCIAL

Denise Benoit

Contracts Manager

GE Energy Management Energy Consulting
General Electric International, Inc.
1 River Road
Building 53, Room 311A
Schenectady, NY 12345 USA

Phone: (518)-385-0901

Fax: (518) 385-9529

denise.benoit@ge.com

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GE Project Team

- Dr. Bahman Daryanian – Smart Grid and DA Technology
- Mr. Lavelle Freeman – Distribution Hardening Initiatives
- Dr. Suresh Gautam - Distribution Hardening Initiatives
- Mr. Matt Lecar - Smart Grid and DA Technology
- Mr. York Moehlenkamp – Substation Hardening Strategies
- Mr. Alassane NDour - Major Event Reporting Requirements
- Mr. Steve Oltmanns - Backup Power for Substations and Communications
- Mr. Ray Piasecki - Smart Grid and DA Technology
- Dr. Slobodan Matic - Smart Grid and DA Technology
- Mr. Everett Whitaker - Major Event Reporting Requirements

GE Reviewers/Advisors

- Dr. Jovan Bebic – Managing Director, Power Systems Operation and Planning
- Dr. Hamid Elahi – General Manager, Energy Consulting
- Ms. Elizabeth Larose - Managing Director, Power Economics

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ACRONYMS AND NOMENCLATURE

Term	Name
AC	Alternative Current
ACE	Atlantic City Electric
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act
ASCE	American Society of Civil Engineers
ATS	Automatic Transfer Switch
AVL	Automatic Vehicle Location
Bbl	Barrel
BEMS	Building Energy Management System
BG&E	Baltimore Gas & Electric
BPU	Bureau of Public Utilities
BTU	British Thermal Unit
CF	Capacity Factor
CFO	Critical Flash Over
CHP	Combined Heat and Power
CIS	Customer Information System
CO	Central Office
CO2	Carbon Dioxide
DA	Distribution Automation
DC	Direct Current
DER	Distributed Energy Resource
DG	Distributed Generation
DMS	Distribution Management System
DOE	U.S. Department of Energy
DR	Demand Response
DTE	Detroit Edison
EDC	Electric Distribution Company
EEI	Edison Electric Institute
EISA	Energy Independence and Security Act
EMF	Electro-Magnetic Field
EMS	Energy Management System
EPB	Electric Power Board (Chattanooga, Tennessee)
EPP	Emergency Preparedness Partners
EPRI	Electric Power Research Institute
ETR	Estimated Time of Restoration
FAN	Field Area Network
FCC	Federal Communications Commission
FCI	Fault Current Indicator
FEMA	Federal Emergency Management Agency
FLISR	Fault Location, Isolation, and Service Restoration
FMEA	Failure Modes and Effects Analysis

Term	Name
FPL	Florida Power and Light
GBI	Ground Based Inspection
GE	General Electric International, Inc. / GE Energy Consulting
GIS	Geographic Information System
GPS	Global Positioning System
GWA	GridWise Alliance
HOMER	Hybrid Optimization of Multiple Energy Resources
HR	Heat Rate
HV	High Voltage
I&M	Inspection and Maintenance
ICT	Information and Communications Technology
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
JCP&L	Jersey Central Power & Light
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lbs	Pounds (British Imperial Mass Unit)
MER	Major Event Report
MG	Microgrid
MHz	Mega Hertz
MMBtu	Millions of BTU
MTTR	Mean Time To Repair
MV	Medium Voltage
MVA	Megavolt Ampere
MW	Megawatt
MWh	Megawatt Hour
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NIMBY	"Not In My Back Yard"
NIST	National Institute of Standards and Technology
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NYS DHSES	NY State Division of Homeland Security and Emergency Services
NYS DPS	New York State Department of Public Service
NYSERDA	New York State Energy and Research Development Authority
O&M	Operations & Maintenance
O&R	Orange & Rockland Utilities
OMS	Outage Management System
P&C	Protection and Control
PECO	Philadelphia Electric Company
PEPCO	Potomac Electric Power Company
PMU	Phasor Measurement Unit

Term	Name
PSC	Public Service Commission
PSE&G	Public Service Electric & Gas
PSNH	Public Service of New Hampshire
PUC	Public Utility Commission
PURA	Public Utilities Regulatory Authority
PV	Photovoltaic
REC	Renewable Energy Credit
RECO	Rockland Electric Company
ROW	Right of Way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
RUS	Rural Utility Service
SCADA	Supervisory Control And Data Acquisition
SDG&E	San Diego Gas & Electric Company
SG	Smart Grid
SG-DA	Smart Grid Distribution Automation
SGIP	Smart Grid Interoperability Panel
SOx	Sulfur Oxides
TV	Television
UPS	Uninterrupted Power Supply
V	Volts
VLSE	Very large scale event
VM	Vegetation Management
VOM	Variable Operations and Maintenance
VPN	Virtual Private Network
WAN	Wide Area Network

EXECUTIVE SUMMARY

Over the last three years, the State of New Jersey has experienced several unprecedented weather events, including Hurricane Irene in August of 2011, a massive early snowstorm in October of 2011, and Superstorm Sandy in November of 2012. These events severely damaged electrical infrastructure, created significant outages across the state, and disrupted economic activity. In the aftermath of this heightened storm activity, The New Jersey Board of Public Utilities ("The BPU") ordered the Electric Distribution Companies (EDCs) to submit plans with initiatives to improve their ability to withstand and recover from severe storms. The submissions included specific plans for infrastructure hardening, as well as Smart Grid and distribution automation investments. Pursuant to the BPU orders, Request for Proposals No # 2380 was issued by Rutgers, The State University of New Jersey, on behalf of the State of NJ, Board of Public Utilities, Office of Clean Energy to "review the EDC Major Storm Response submissions and comment on the appropriateness, prudence and engineering validity, where appropriate, of the EDC submissions and plans."

In executing this work, GE Energy Consulting has drawn upon its expertise in distribution planning, engineering and operations, its many years of experience working with electric utilities, and the breadth and depth of the GE Energy Management business. The GE team relied on engineering judgment and critical analysis to review and assess 29 reports and plans submitted by the New Jersey EDCs. The team conducted eight interviews with utility and industry experts and reviewed over 60 publicly available reports from other utilities, state commissions, government agencies, industry organizations, and consultants to develop context, identify reference cases, and establish best practices. Over the course of the study, one of the key observations is that *higher fidelity data needs to be gathered so that more granular analyses can be performed*. This would enable targeted application of distribution hardening initiatives, substation hardening strategies, and Smart Grid and distribution automation technology.

Following a presentation to the Commissioners on August 1, 2014 in Trenton, NJ, the Board expressed a strong desire for "actionable items" that would lead to improved reliability and resiliency. Consequently, GE consolidated the original scope into four (4) main subject areas, developed key recommendations for each subject area, and supplemented each recommendation with a roadmap for implementation (where possible).

The main activities conducted under each subject area are listed below:

1. Assess the EDC major event reports (MERs) and make recommendations for improvements to the EDC reporting requirements.
2. Evaluate the potential impact of various distribution hardening initiatives on reliability and resiliency in New Jersey, and make specific recommendations for vegetation management, undergrounding, ground-based inspection, and infrastructure upgrades.
3. Discuss benefits and costs of substation hardening strategies and make recommendations for flood avoidance, flood control, and backup power for substations and communications facilities.
4. Review EDC smart grid and distribution automation plans (SGDAP) filed in compliance with BPU-63 and BPU-65 to evaluate their potential to impact reliability and resiliency, and make recommendations that would help the BPU determine the benefit of proposed investments.

As part of this work, GE presents concrete recommendations to improve storm resiliency and system reliability by (1) giving the BPU more insight into the extent and causes of storm damage, restoration times and recovery costs, and (2) prescribing actions that EDCs can take to improve performance during future storms.

GE recognizes that due to the broad scope of activities that the recommendations encompass, they are not equal in terms of impact on storm resiliency, and cost to the EDCs. Therefore, feedback on the recommendations was solicited and received from the BPU Staff with respect to the following attributes: appeal, implementation ease (for the BPU and for EDCs), potential impact, and conformity with existing policy.

Each of the key recommendations is briefly discussed below in the context of the four (4) major subject areas listed above. Following the discussions, the recommendations are prioritized in terms of estimated cost, potential impact on storm resiliency, and whether they are immediately actionable.

ES.1 EDC Major Event Reports

This task reviewed data contained in individual EDC Major Event Reports (MERs) to: (1) evaluate the usefulness of the MERs for providing insight into the causes of infrastructure damage and costs of restoration; and (2) suggest recommendations for improving their quality and consistency.

A total of nine (9) MERs on Hurricane Irene, the October 2011 snowstorm, and Superstorm Sandy from the four (4) EDCs were received and reviewed against the requirements of the pertinent rule, N.J.A.C. 14:5-8.8. The table below shows the MERs that were provided to GE by the BPU for review.

EDC Major Event Reports Reviewed

	ACE	JCP&L	PSE&G	RECO
Hurricane Irene		✓	✓	✓
October 2011 Snowstorm		✓		✓
Hurricane Sandy	✓	✓	✓	✓

✓ = EDC MER was made available

All of the EDC MERs are compliant with the letter of the rule's requirements but they do not provide sufficient insight to enable comprehensive post-event analysis. Because some requirements are open to interpretation, the submissions lack consistency on what types of information are included and how data are displayed. For example, The MER Rule requires the EDCs to report "*the number of trouble locations and classifications*." This requirement is interpreted differently by the EDCs: one EDC lists the number of trouble orders and outage orders by region; another lists the T&D equipment damaged by type; and yet another provides the causes of customer outages. This inconsistency limits the usefulness of the information for benchmarking storm restoration performance across EDCs. The MER Rule does not explicitly compel EDCs to report the extent and causes of infrastructure damage, and costs of restoration. Consequently, this critical information is not universally available in the MERs.

The table below summarizes the content of the EDC MERs with respect to the items that GE was asked to evaluate in this task.

Summary of Information in EDC MERs Pertinent to Study Scope

	ACE	JCP&L	PSE&G	RECO
Customer Outages	Frequency charts of outages + data table	Frequency charts of outages	Cumulative charts of interruptions and restorations	Data table of customers affected, restored, remaining
Infrastructure Damage	None	For Irene only; in attachment	For T&D and substations	For T&D
Cause of Damage	None	None	For stations (flooding) and major loads	None
Recovery Costs	None	None	None	None

The results of the review (exemplified by the information in the table above) confirm that current EDC major event reports, on the whole, do not give sufficient insight into:

- Damage extent and causes
- Recovery costs
- Communications during event
- Damage assessment and estimated times of restoration (ETRs)
- Post-event lessons learned
- Comparative EDC performance

New Jersey has an opportunity to leverage reporting requirements and standards from other Northeast states to facilitate best-in-class post-event analysis. To achieve this goal, GE makes the following recommendation to the BPU:

MR-1: <u>Enhance</u> Electric Distribution Company <u>Major Event Reporting</u> requirements <u>to enable comparative and quantitative assessment</u> of EDC preparation and restoration actions, and scorecard-based performance assessments.

Following this recommendation will improve quality and consistency of the MERs and enable the BPU staff to perform comparative analyses to objectively assess: how much damage was caused by an event relative to previous events; the causes of damage; speed of restoration vs. severity of damage; what factors contributed to response time; and recovery costs relative to storm intensity. The implementation steps include developing consistent data collection templates, prescribing standardized comparison graphs and charts, and adoption of a performance standard and scorecard methodology for assessment of EDC storm response. Sample templates for data collection are described in Chapter 2 of the main report.

ES.2 Distribution Hardening

Storm-hardening activities aim to reduce the impact of future storms by planning, designing, and maintaining the electrical infrastructure to make it less susceptible to physical damage (from high winds, falling trees, flood, etc.), and to make it easier to reestablish service after storm-related outages. In the domain of storm hardening, some of the more common activities include (in no particular order): vegetation management; placing circuits underground; upgrading poles and hardware; and more frequent inspection and maintenance of distribution structure and equipment. Each of these initiatives is briefly discussed in this subsection.

ES.2.1 Vegetation Management

Data from the EDC major event reports and other sources (such as the EPP Report on the Performance of EDCs in 2011 Major Storms and the FERC Report on Transmission Facility Outages during the October 2011 Northeast Snowstorm) clearly substantiate the fact that downed trees and tree-related damage, especially from trees outside EDC clearance zones, were major causes of outages, infrastructure damage, and delayed response during the recent storms.

Trimming trees within the clearance zones maintains and improves reliability under "normal" operating conditions, but storm experiences have shown that it may not have a significant impact on reducing the number of outages in major storms. JCP&L's experience during the October 2011 snowstorm, as well as other EDC storm experiences, confirm that mitigating the impact of danger trees outside the right-of-way (off-ROW danger trees) has the most potential (from a vegetation management perspective) to reduce storm damage, decrease the number of customer outages, and speed up restoration time.

Based on these observations, GE makes the following five (5) vegetation management-related recommendations to the BPU:

DH-1: <u>Track off-ROW trees</u> posing risk of outages; <u>predict</u> and report associated <u>damage</u>, number of customer interruptions, and restoration time by danger tree.

This recommendation enables a tree-centric view of the impact off-ROW trees. EDC forestry departments routinely identify danger trees within the clearance zone, but (according to the EPP Report) only ACE reports keeping data on off-ROW danger trees. EDCs should be required to track preventable (due to trees within the ROW) and non-preventable (due to trees outside the ROW) tree-related outages and report the extent of infrastructure damage, customer outages, and delays in response due to off-ROW danger trees in their MERs (consistent with the earlier recommendation). With information on the location of off-ROW danger trees relative to distribution circuits, EDCs can simulate faults at the tree locations and tabulate the number of customers affected and MWs unserved due to tree impact. Using historical reliability and storm data, the infrastructure damage (broken pole, downed wire, damaged transformer, etc.) could also be estimated. These results can be prorated by the probability of weather events to give statistically representative estimates.

DH-2: <u>Segment</u> customers by restoration priority; <u>calculate</u> and report an <u>estimate of hours out of service</u> due to tree damage during normal weather <u>for each customer</u>.

This recommendation enables a customer-centric view of the impact of off-ROW trees, providing insight into the degradation in service for different categories of ratepayers. Customers who are served by circuits adjacent to off-ROW danger trees will most likely eventually be interrupted by tree-related events, whether during storms or blue-sky days. However, not all customers are equally likely to be impacted. EDCs can segregate customers by level of exposure, remediation measure, and restoration priority, and allocate the likely outages caused by off-ROW danger trees (computed in recommendation DH-1), to the affected customers in each category. In this manner, the predicted total hours of service interruption per year for each customer due to off-ROW tree events can be aggregated. These results can also be prorated by the probability of weather events to give statistically representative estimates.

DH-3: <u>Communicate estimates to customers</u> and provide convenient mechanisms for customers to report danger trees (e.g. via twitter feeds).

This recommendation will enable EDCs to use the insight from recommendations DH-1 and DH-2 to drive customer engagement, and incorporate crowd-sourcing into utility operations. Each NJ EDC currently provides at least one mechanism for customers to report outages, but none give customers the ability to report suspicious or potentially dangerous situations (such as a danger tree or rotting pole) *and* upload photos. With knowledge about the potential impact of danger trees in their neighborhood (via bill inserts or door hangers for example), customers may be motivated and should be encouraged to use Social Media, Mobile Apps, SMS, Email, and Storm Portals to report suspected danger trees in their neighborhoods and, importantly, upload photos to the utility. This could help to focus utility efforts on immediate problems, use vegetation patrol budgets more effectively, and potentially reduce costs.

DH-4: Where justified, <u>grant</u> EDCs <u>the authority to remove danger trees</u> outside the clearance zone.

A desirable (and likely) outcome of increased customer awareness and vigilance is pressure on landowners and municipalities to: (1) remove off-ROW danger trees with high potential to impact reliability and resiliency; or (2) allow utilities to remove or treat them. During the October 2011 snowstorm in the Northeast, the FERC Report on Transmission Facility Outages stated that "… *off-right-of-way fall-ins accounted for … nearly 75% of all confirmed tree-related outages*." The EPP report on Performance of EDCs in 2011 Major Storms noted that "*across the utility industry, between 20 to 50% of all unplanned distribution outages are tree-related, with a majority caused by tree failures outside the ROW*." The EPP Report also stated that "*on a daily basis, 80-85% of tree related outages are from trees out of ROW*." These statements are consistent with what GE has seen and heard in the industry. Based on these observations, the case can be made that, *where justified*, if utilities are empowered (via eminent domain for example) to remove, trim or treat potentially hazardous trees outside the energized corridor, blue-sky reliability and storm resiliency would improve. The case is compelling enough that several states and jurisdictions (CA, CT, IL) currently have regulatory decisions or legislative proposals that give utilities more latitude to address off-ROW danger trees.

DH-5: <u>Determine</u> the <u>most cost-effective level of tree-trimming</u> and optimal corridor width by circuit or segment using vegetation data and other relevant inputs.

Evidence in the EDC major event reports, and other sources (such as the FERC and EPP reports quoted above) clearly show that trees are a common root-cause of reliability and resiliency problems on circuits in New Jersey. However, the state of New Jersey is quite diverse, and some

EDCs are more prone to tree-related outages than others. Even within a particular EDC service area, the need for tree trimming and the extent of trimming can vary significantly by substation area, feeder or even segment. With access to more data than ever before, advanced tools and analytics, it is quite possible to prioritize and customize vegetation management activities even down to a circuit segment. Based on historical data, EDCs can determine the statistical correlation between tree-trimming cycle/corridor width and outages during normal days and storm days. The resulting relationship can be used to adjust circuit failure rates by segment in a reliability model in order to simulate changes in vegetation management practices. Based on the results, EDCs can customize the level of trim (both cycle and width) per segment to achieve a specified expected level of reliability. The goal is to make the best use of the vegetation management budget to maintain or improve reliability and (by extension) resiliency. GE conducted a proof-of-concept at a major North American utility. Even with limited data, the trial showed that reliability could be maintained or even improved with a reduction of 10% in the nearly $200M vegetation budget.

ES.2.2 Undergrounding

Converting existing overhead lines to underground circuits can prevent storm-related outages in situations where vegetation, wind, ice and snow loading are a problem. But depending on the location of facilities, underground systems may sustain more damage than overhead systems (e.g. from flooding and storm surge). Several studies[1] have also shown that the cost of burying power lines can be 2 to 10 times the cost to build overhead lines, depending on the location. Consequently, several states and utilities have concluded that *targeted* or *selective* undergrounding is a viable solution to hardening the infrastructure, rather than a total conversion. One example is Dominion Virginia Power which initiated a 12-year program to bury 350 miles of taps per year at an annual cost of approximately $175 million with a goal to cut storm restoration time in half. Historical data showed that 50% of major storm damage was occurring on 20% of overhead tap lines, so undergrounding these taps would improve resiliency. Another East Coast utility, PEPCO, has submitted a plan to the DC PSC to underground the main trunk and laterals of about 60 feeders (one-third of their overhead feeders) over 7 to 10 years at a cost of approximately $1 billion. This is partially based on studies that project a decrease of 1.4 primary outage incidents per circuit-mile.

Based on these cases, industry experience, and engineering judgment, GE makes the following recommendation for the Board:

DH-6: Selectively underground the most critical distribution feeders and tap lines, where practical, to improve reliability and reduce major storm restoration time.

Several of the vegetation management-related recommendations advocated predicting and reporting the impact of off-ROW danger trees, and removing them where justified. However, it is obviously impractical to remove all danger trees, even for transmission (as the FERC report on the October 2011 snowstorm shows). Undergrounding has high potential to reduce storm impact but widespread adoption is cost-prohibitive. New Jersey can leverage experiences from other jurisdictions (such as FL, VA, MD, DC, TX, NC) to select the most critical feeders and segments for

[1] An assessment of publically available documentation by InfraSource Technology can be found in "*Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*," February 2007. Another excellent source is the EEI's "*Before and After the Storm: A Compilation Recent Studies, Programs, and Policies Related To Storm Hardening and Resiliency*," updated March 2014.

undergrounding. EDCs can prioritize critical distribution feeders and tap lines for undergrounding using a general multi-criteria ranking methodology. The approach would incorporate circuit attributes like reliability, storm performance history, customer profile, age, etc. The output of this process would be a list of critical circuits/segments/taps with attributes that make them attractive candidates for undergrounding, and a documented, defensible methodology for justifying the rankings.

ES.2.3 Ground-based Inspection

Deteriorated poles and equipment are more likely to fail during storms, leading to more outages and delayed restoration. The State of New Jersey is considering requiring annual inspections of overhead lines as a way to harden the infrastructure against storm damage. This one-year inspection cycle is more frequent than what is prescribed by the Rural Utility Service (RUS) decay severity map for New Jersey (8 to 10 years), and more than what several other Northeast states use as a minimum standard. An annual inspection is typically a visual inspection of the pole and equipment for obvious defects, signs of wear, and safety issues, often with sounding (with a hammer) for integrity. The total estimated cost of annual ground-based inspection for the NJ EDCs is approximately $24 million (which is roughly 26% of the EDCs estimated collective vegetation management expenditure, for scale). In his review of wood pole inspection programs, Daugherty (1998)[2] presents data and references to show that a more invasive method at a lower frequency (e.g. 18 to 24 inch excavation plus sound and bore every 6 to 10 years) could actually be more effective at identifying reject and priority poles than annual visual inspection alone. The data showed that the more invasive inspection method at a lower frequency would find 98% of reject and priority poles while visual inspection alone would miss most. In other words, the method of inspection is likely a greater determinant of success than the frequency of inspection.

The general methodology applied in recommendation DH-5 to determine the most cost-effective level of tree-trimming and corridor width can also be applied here to develop appropriate inspection cycles and techniques that are targeted toward priority feeders. These observations lead to the following recommendation for the Board:

DH-7: Determine the most cost-effective inspection cycle and method for poles and associated equipment by circuit, and prioritize based on criticality and condition.

This recommendation will allow the EDCs to prioritize ground-based inspection based on criticality and condition of the circuit, and permit more rigorous techniques to be applied to critical circuits than what may be practical or feasible with annual cyclic inspection. Similar to recommendation DH-5, EDCs can determine the statistical correlation between inspection cycle/method and circuit reliability (SAIDI, SAIFI, CAIDI). The resulting transfer function can be used to adjust circuit failure rates by segment in a reliability model in order to simulate changes in inspection practices. Based on the results, EDCs can customize the level of inspection (both cycle and method) per segment to achieve a specified expected level of reliability. The goal is to make the best use of the ground-based inspection budget to maintain or improve reliability and (by proxy) resiliency.

[2] Gerald L. Daugherty, The Realistic Expectation of an In-Place Wood Pole Inspection Program, 1998

ES.2.4 Pole and Hardware Upgrades

Large portions of the existing distribution infrastructure were designed using wind loading averaged over wide geographic areas (per NESC district loading maps, Rule 250B). The result is that the most common class of distribution wood pole construction is Grade C. Grade B, which is 50% stronger, is used in extreme loading conditions (NESC Rule 250C and Rule 250D) for construction over 60 feet (usually transmission). Failures of wood pole construction during major storms (from wind and ice loading) has prompted utilities in states vulnerable to wind and ice storms to consider upgrading their T&D structures for reliability and resiliency purposes. A number of industry studies that reference higher design and construction standards for overhead lines (such as the EEI Report, "Before and After the Storm") have concluded that widespread system hardening is cost-prohibitive and a targeted approach is most effective. Based these studies and experiences in Florida and New Hampshire particularly, the following recommendation can be made to the Board:

DH-8: <u>Upgrade T&D construction</u> near coastal areas to NESC Grade B, <u>and incorporate extreme wind and ice loading</u> criteria in all T&D design, regardless of height.

As mentioned earlier, the widespread use of Grade C construction for distribution is based on NESC Rule 250B district loading maps. The rule uses average ice and wind loading over large parts of the country and does not sufficiently incorporate local factors. ASCE extreme wind and ice loading criteria, which are the basis for NESC Rule 250C and 250D, lead to more resilient designs, but the current NESC revision (2007) only requires them for structures over 60 feet. Areas near the New Jersey coast are vulnerable to extreme wind and ice loading. Three-second wind gusts between 110 and 120 mph can occur at a height of 33 feet above ground within 10 to 15 miles of the coast. Targeted upgrade of distribution circuits near the coast to Grade B construction and incorporating extreme wind and ice loading criteria in T&D designs, not just lines over 60 feet, will lead to more storm-resilient structures. Florida Power and Light, for example, has been designing distribution lines to the NESC extreme wind loading criteria for many years, despite the fact that they are in "Light" zone of the NESC district loading map.

ES.3 Substation Hardening

Flood damage at electrical substations was a major issue for some New Jersey EDCs during Hurricanes Irene and Sandy. PSE&G and JCP&L reported flood damage to 15 substations during Irene, and 20 during Sandy. All were located in the 100-year flood zone. The impacts to the stations included damage to relays, breakers, controls, bushings, bus work, and auxiliary and backup power systems. The two main strategies to combat such issues at substations are flood control and flood avoidance.

ES.3.1 Flood Control and Avoidance

Due to high costs and operating constraints (stations must be located near loads and many critical loads are near the coast), substation equipment is typically only relocated vertically to mitigate flood impacts. GE experience with several electric utilities indicates that substations are only relocated (horizontally) to new sites under extreme circumstances, such as failure of all substation yard foundations. Additionally, through interviews with four utilities in the Northeast and Midwest, GE found that others faced with similar storms as New Jersey EDCs are using discrete, asset-focused (smaller scale) strategies for flood control and avoidance, rather than relocating entire substations. Based on experience with substation design and construction, GE determined that relocating or constructing new substations is less cost-effective than implementing smaller scale strategies for individual or groups of equipment.

The EDC major event report filings do not indicate that the EDCs are routinely quantifying the risk of exposure and the cost of remediation. Consequently, GE believes there is an opportunity to use rigorous analytical processes to determine the critical assets for application of flood control strategies. The GE report reviews the impact and cost of various flood control and flood avoidance strategies, and makes the following key recommendations to the Board to improve substation resiliency:

SH-1: Add elevation attributes to every flood-prone asset in a substation equipment database; report number of assets below the 100-year flood and storm surge elevation plus 1 foot.

GE recommends that each New Jersey EDC utilize an existing database or create a new database for substation equipment. The EDCs should include elevation attributes for every flood-prone asset and report the number of assets below a defined critical flood elevation. This critical flood elevation could be defined as the 100-year flood elevation or the FEMA advisory base flood elevation plus one (1) foot.

SH-2: Perform limited failure modes and effects analysis (FMEA) for substations using weather events as the modes with customer outages and substation equipment failure as an effect; report findings.

GE recommends that each New Jersey EDC perform a limited Failure Modes and Effects Analysis (FMEA) for flood-prone assets and report the results of the analysis. The EDCs should perform the analysis using weather events as the modes with customer outages and substation equipment failures as the effect. The results of the FMEA will provide a relative risk of substation equipment failure. This relative risk can be used to prioritize repairs, modifications, or inspections of flood-prone assets.

SH-3: Rank findings, estimate and report costs of hardening substation equipment to eliminate the top 20% of equipment failures leading to customer outages as identified in SH-2.

GE recommends that each New Jersey EDC rank the flood-prone assets based on the relative risk of failure as determined by the results of the analysis from the preceding recommendation. The EDCs should estimate and report the costs of hardening substation equipment against the defined weather events in order to eliminate a prescribed percentage of customer outages and equipment failures.

SH-4: Estimate and report costs of regular inspection for critical assets as identified in recommendation SH-2; optimize inspection cycles to achieve highest impact with lowest cost.

GE recommends that each New Jersey EDC estimate and report costs of regular inspections of critical assets. The EDCs should create and implement an inspection program for critical assets or modify an existing program. Inspection cycles should be adjusted on an ongoing basis to achieve the highest impact with the lowest cost.

ES.3.2 Backup Power for Substations and Communications

Substation battery systems are generally designed to support the substation controls without the battery charger and/or AC supply for a period of up to eight (8) hours. Once the battery supporting the DC power supply system in the substation has been discharged to the point where the substation controls are compromised, the controls (monitoring, switching, communications, and protection) cannot function until the battery charger and/or AC supply to the substation is able to restore power to the battery and the DC power supply system. In the EDC MERs, there are several reported incidents of damage to substation batteries. However, GE did not find any evidence to suggest that substation battery or battery charger failure *alone* was the underlying cause for customer service interruptions. A 2009 Quanta Report to the Texas PUC concluded that broad deployment of minimal back-up generation was not cost effective, but that a more detailed analysis at the individual substation level is needed to "appropriately assess cost and benefits."

In the previous section, GE presented several recommendations for substation hardening. The FMEA and ranking process outlined in the recommendations are designed to elicit whether substation DC power failure during weather events is a driver of substation unavailability. If the detailed analysis reveals that battery backup is indeed a failure mode, then backup power or alternate supply to the battery charger will be one of the hardening options that merit consideration.

Based on a discussion of benefits and cost-effectiveness of backup power to substations and communication facilities, GE makes the following recommendations to the Board:

SH-5: Identify and report communications facilities critical to restoration process; estimate and report costs of providing backup power to cover 3-sigma of expected storm restoration time.

Communication facilities are a high-priority restoration target, but it may still take several hours to restore power after a storm. This recommendation will provide insight into how much backup power is needed at communication facilities to maintain command and control during a prolonged outage. This recommendation requires that the EDCs install adequate back-up generators at each of their business-critical communication facility locations with sufficient secure on-site fuel storage capacity to support an adequate period of generator operation, after which time additional fuel supply can be delivered to the site. Historical power outage data should be analyzed, to determine the mean power outage duration, and the "3-sigma" statistic should be estimated to determine the "adequate period of generator operation" that both the back-up generator and the secure on-site fuel storage should accommodate.

SH-6: Require EDCs to include quick deployment of mobile substations and mobile backup generator equipment in emergency response plans for various catastrophic events across NJ.

The EDC major event reports and other reports confirm that several EDCs deployed mobile substations and large portable generators during the recent major storms. GE recommends that the BPU formalize this as a best practice, and require the EDCs to include quick deployment of an adequate number of both mobile substations and mobile back-up generation equipment in their emergency response plans. A similar process (to the one described for communication facilities) can be used to determine the statistical period for which mobile substations and mobile backup generator equipment are needed before the system can be restored. This will help to determine what an "adequate number" for deployment is likely to be.

ES.4 Smart Grid & Distribution Automation Initiatives

To set the context for this evaluation, GE discusses the background of federal and U.S. industry-led initiatives, including available results from the US DOE and EPRI Smart Grid pilots. The discussion summarizes key findings from a review of the literature on the current state of SG-DA and related technology, and emerging applications for storm resiliency, with particular attention to the Northeast states and other storm-prone regions of the U.S.

ES.4.1 Smart Grid DA Investments

The American Recovery and Reinvestment Act (ARRA) of 2009 provided the U.S. Department of Energy with $4.5 billion to modernize the electric power grid and implement Title XIII of the Energy Independence and Security Act (EISA). With matching utility funding for many programs, the total investment in Smart Grid resulting from ARRA is expected to reach $7.9 billion. Of the total ARRA investment, $1.96 billion was directed towards distribution system equipment (not including AMI and customer-side technologies) in 57 projects. Forty-eight of these projects targeted reliability improvement but *none were specifically aimed at storm resiliency*. Results from four projects (covering a collective 1,250 circuits) reveal that while the benefits vary widely among circuits depending on a number of factors, a 20-40% improvement in reliability (i.e. reduction in SAIFI, MAIFI and SAIDI) was achieved in most cases.

Another significant body of Smart Grid pilot experience is the set of 24 on-going utility programs included under the Electric Power Research Institute's (EPRI's) Smart Grid Demonstration Initiative (SGDI), which includes, in addition to U.S. participants, utilities from Australia, Canada, France, Ireland and Japan. As of mid-2013, most pilots had moved into the "data collection" and "analysis" phases, with completion expected by 2015. None of the case studies reported in the recent five-year update appears directly targeted at storm resiliency.

Based on the observed lack of data and models to quantify the impact of SG-DA technologies on storm resiliency, GE believes that New Jersey can: (1) lay the groundwork for quantifying the additional benefits SG-DA provides for resiliency during future storms; and (2) leverage industry practices to adopt a consistent reporting framework to allow comparative evaluation and benchmarking of EDC plans. To facilitate these goals, GE makes the following recommendation to the Board:

SG-1: <u>Mandate</u> that <u>EDCs assess impact of reliability-oriented SG-DA and create investment and deployment plans</u> for the most impactful technologies for their service territory.

Since models for assessing SG-DA resiliency impact and the associated cost/benefits do not presently exist, a screening analysis for prudency of investment can be based on available reliability assessment models, which would provide a floor for the expected resiliency benefits. Investments that are cost-effective under ordinary circumstances and can provide additional benefits during major storms should be approved. However, there is no " "one-size-fits-all" solution, since diverse service territories with different circuits behave differently under DA. Future investments should target SG-DA to those circuit types and locations that provide the most benefit at lowest cost, i.e. where the value of reliability improvement (as measured by avoided cost for example) exceeds the cost to ratepayers.

ES.4.2 Reliability vs. Resiliency

Many states, including New Jersey, permit utilities to exclude major events (those that affect a large percentage of a utility's customers for an extended period of time) from the standard reliability metrics reported to the regulating authority (SAIDI, SAIFI, CAIDI, MAIFI, etc.). This is reasonable since reliability metrics are meant to reflect the ability of the system (design and operation) to deliver power to customers under "normal" conditions. However, there are no commonly accepted metrics for performance during storms or major events (although some jurisdictions such as MD and NY have proposed performance standards and scorecard-based assessment methods).

There are industry accepted models to assess system reliability benefit of SG-DA, but no models currently exist to simulate and assess the impact of SG-DA during major storms; and very little actual field data is available for validation. One of the prevailing issues is that during the initial response to a major event closed-loop automation is typically turned off to prevent accidental damage to utility equipment or personnel, as switches are reset and circuits re-energized. Once the storm has subsided, communications have been re-established, and an initial damage assessment can be safely conducted, the automated systems are allowed to operate again. In this post-damage assessment phase, there is strong anecdotal evidence to suggest that SG-DA will be beneficial to the restoration effort, but models and data to support this are not available yet.

Because the lack of standard industry metrics, models and data for quantifying the resiliency benefits of SG-DA, GE believes that New Jersey has an opportunity to close this gap. While pursuing SG-DA investments that are economically justified on their reliability merits alone, New Jersey can also lay the groundwork for quantifying the additional benefits DA provides for resiliency during future storms. GE makes the following recommendations to the Board:

SG-2: <u>Target deployment plans to evaluate SG-DA technology effectiveness</u> for resiliency by strategic deployment on subsets of circuits with similar storm exposure and physical attributes.

Specifically, GE recommends that the BPU target a portion of SG-DA deployments to subsets of distribution circuits with high storm exposure. By tracking the performance of these circuits, alongside similarly-situated circuits that do not receive SG-DA investment, the BPU will be able to evaluate and quantify the resiliency improvements directly attributable to automation. In the future, this should allow the New Jersey EDCs to identify those technologies and circuit attributes that have the greatest potential for resiliency benefit, and to fully incorporate these benefits into the business case for consideration of additional SG-DA investment.

SG-3: Define and mandate reporting requirements to <u>track effectiveness</u> of SG-DA technologies in storm recovery activities.

Analytical models for projecting SG-DA resiliency impact and the associated cost/benefits do not presently exist. However, EDCs can collect actual/empirical information from future storm events in order to quantify the resiliency and storm recovery impact of implemented SG-DA on their systems. Examples of empirical data include cumulative number of customer-hours out, MW unserved, and associated temporal charts as discussed in the MER Recommendation (MR-1). These data can be used to assess additional SG-DA investments and target those investments towards the locations and types of circuits that will see the strongest storm resiliency benefits.

ES.4.3 Industry SG-DA Practices and Trends

While historically the focus of SG-DA technologies has been on modernizing the distribution system to improve energy efficiency, productivity and blue-sky reliability, there has been a recent shift toward evaluating and verifying the storm/resiliency benefits of SG-DA technologies. There is a wide array of SG and DA technologies that have the potential to improve operations and reduce restoration costs during storm events. These include applications inside the utility control room and out on the electric distribution system (from the distribution substation to the meter).

The long-term direction of the trend in SG-DA technologies is towards a higher degree of situational awareness for the utility operator. The seamless integration and coordination of SG-DA applications enables movement of relevant information between the field, operations center, and back office in a time sensitive fashion. This allows the operations center to efficiently coordinate and schedule the activities and movement of restoration crews and assets, in response to a storm or other emergency event. Based on industry trends and practices, GE makes the following recommendation to the Board:

SG-4: Require EDCs to <u>quantify potential improvement</u> in damage forecasts <u>using storm tracking and damage prediction</u> tools, and assess resulting improvement in storm response.

As part of their emergency response plan, utilities are often required to describe how they track storms, predict damage, stage and position crews in anticipation of damage. This recommendation requires utilities to evaluate the use of computer models for damage prediction. A possible evaluation approach (back-casting) is: (1) EDC provides historical day-ahead (or other period) weather forecast for a recent storm, and system physical and electrical characteristics (at the time of storm) to a vendor/consultant; (2) vendor/consultant produces forecast of storm damage for that time period; and (3) EDC compares vendor's forecast with actual historical EDC storm damage data and evaluates possible improvement in storm response as a result of having improved forecasts. If the evaluation warrants eventual implementation, the advanced data analytics software will leverage the full range of historical and real time weather and utility data to perform analysis of circuit and equipment failure potential, anticipate the number of outages, identify high likelihood locations, and project crew requirements and estimated times of restoration.

ES.4.4 Review of EDC Smart Grid and Distribution Automation Plans (SGDAP)

GE conducted a thorough review of the EDC filings submitted in response to BPU Orders 63 and 65. While the individual responses vary in quality and completeness, on the whole, the information presented is inconsistent across EDCs, and does not provide sufficient insight to enable definitive assessment of the EDC plans or make recommendations with regard to any specific plan. Information required in the Order on "*the timeframe for the development of each component and the overall plan, as well as the costs and benefits of each individual component and the entire plan to the EDC and to the ratepayer*" is incomplete and lacking the requisite data and analysis. The EDCs' responses to the request for deployment timeframes and costs for their SG-DA investments also varied in quality and completeness. None of the submissions segregated costs between the EDC and the ratepayer.

The submissions do not provide sufficient information on the benefits of the SG-DA investments or enough detail to enable verification through independent analysis. Based on these observations, GE makes the following recommendation to the Board:

SG-6: Mandate <u>enhanced EDC SGDAP submissions</u> to ensure completeness, and to enable comparative evaluation and benchmarking of SG-DA investment plans.

GE recommends that the BPU adopt a consistent submission/reporting framework for the New Jersey EDCs that would allow for comparative evaluation and benchmarking, both across the EDCS and with other utilities outside New Jersey. The framework would include firm requirements for the report narrative, as well as a questionnaire or reporting checklist of required data elements for each SG-DA project or technology element. At a minimum, the narrative should include explanation of the technology or device, main function, location, and deployment scale, existing state of the technology deployment, timeframe for implementation, cost to the EDC, cost to ratepayers, benefits to EDC, and benefits to ratepayers. Industry standard approaches like the Carnegie Melon Smart Grid Maturity Model can be used to score the EDC plans.

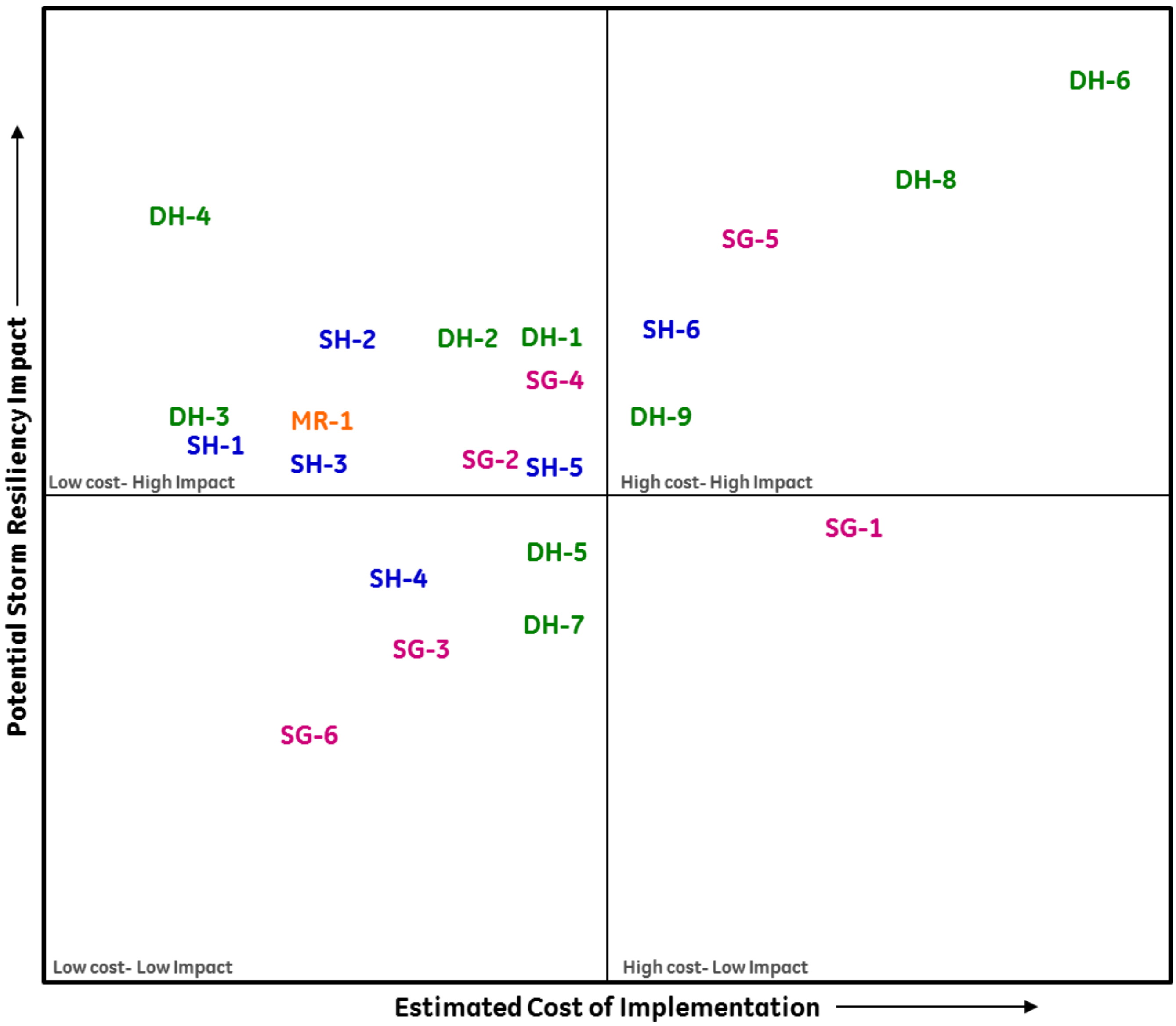
ES.5 Cost and Impact of Recommendations

In total, twenty-two (22) key recommendations were distilled from the research, review and evaluation activities. Chapter 6 of the main report presents each recommendation as a succinct statement followed by a rationale and (where applicable) necessary data and plausible steps to implement the recommendation. Over the course of the work, a recurring theme is that *higher fidelity data needs to be gathered to perform more granular analyses for more targeted actions*.

The table below lists each recommendation and indicates whether (in GE's opinion) it is immediately actionable or actionable subject to evaluation. The accompanying 4-block chart segments the recommendations by implementation cost and potential impact on storm resiliency.

Indication of Whether Recommendation is Immediately Actionable or Subject to Evaluation

Immediately Actionable	Actionable Subject to Evaluation
MR-1: Upgrade EDC MER requirements	DH-5: Determine the most cost-effective level of tree-trimming
DH-1: Track and report off-ROW trees; predict outages, damage	DH-6: Selectively underground most critical feeders and tap lines
DH-2: Segment customers; calculate/report hours out due to trees	DH-7: Determine the most cost-effective inspection cycle/method
DH-3 Communicate estimates; provide mechanisms for reporting	DH-8: Upgrade construction near coast; design for extreme loading
DH-4: Grant EDCs authority to remove off-ROW danger trees	DH-9: Insert steel/concrete structures in long straight wood circuits
SH-1 Add elevation attributes to flood-prone assets and report	SH-4 Estimate and report costs of inspection; adjust cycles
SH-2 Perform limited failure modes and effects analysis (FMEA)	SH-5 Identify critical comm. facilities; estimate hardening costs
SH-3 FMEA findings, estimate and report hardening costs	SH-6: Require quick deployment of mobile subs and backup gens
SG-3: Track and report SG-DA effectiveness during storms	SG-1 Asses/deploy most impactful SG-DA technologies
SG-4: Require EDCs to evaluate damage prediction tools	SG-2: Deploy SG-DA technology selectively for resiliency
SG-6: Mandate standard EDC SGDAP reporting	SG-5: Assess the value and feasibility of DG and microgrids



Estimated costs and potential resiliency impact of GE recommendations

1 INTRODUCTION AND BACKGROUND

Extreme weather events and other natural disasters can threaten lives, cripple communities, disrupt economic activity, and lead to devastation of electric utilities' generation, transmission and distribution infrastructure. According to data from the US DOE, outages caused by severe weather such as thunderstorms, hurricanes, and blizzards account for 58 percent of outages observed since 2002 and 87 percent of outages affecting 50,000 or more customers.[1] Over the last three years, the State of New Jersey has experienced several unprecedented weather events, including Hurricane Irene in August of 2011, a massive early snowstorm in October of 2011, and Superstorm Sandy in November of 2012. These events severely damaged electrical infrastructure, created significant outages across the state, disrupted economic activity, and cost the U.S. economy well over a billion dollars (see chart below from the NOAA)[2]. According to some experts, the frequency and intensity of extreme weather events is expected continue even as utilities deal with physical and fiscal resource constraints, increased scrutiny, and rising expectations for performance.

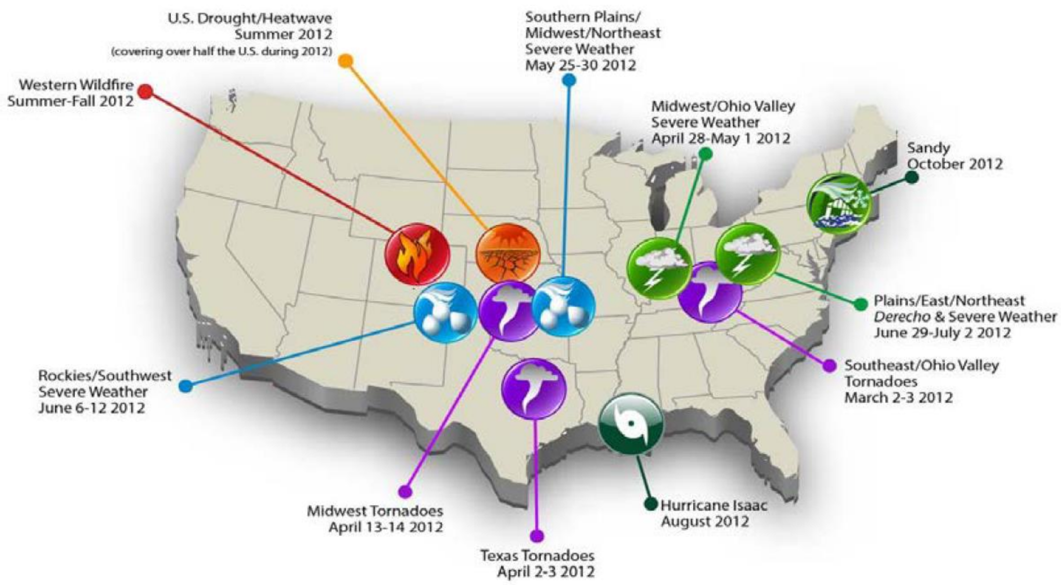


Figure 1-1 U.S. 2012 Billion-dollar weather and climate disasters

In the aftermath of this heightened storm activity, The New Jersey Board of Public Utilities ("The BPU") ordered the Electric Distribution Companies (EDCs) to submit plans with initiatives to improve their ability to withstand and recover from severe storms. The submissions included specific plans for infrastructure hardening, as well as Smart Grid and distribution automation investments. Pursuant to the BPU orders, Request for Proposals No # 2380 was issued by Rutgers, The State University of New Jersey, on behalf of the State of NJ, Board of Public Utilities, Office of Clean Energy to "review the EDC Major Storm Response submissions and comment on the appropriateness, prudence and engineering validity, where appropriate, of the EDC submissions and plans."

[1] Executive Office of the President, Economic Benefits of Increasing Electric Grid Resilience to Weather Outages, Aug 2013

[2] National Oceanic and Atmospheric Administration (NOAA): http://www.ncdc.noaa.gov/billions/

1.1 Original Tasks

The goal of this study, as originally defined by the BPU, was to review EDC plans and make recommendations for:

- Electric Distribution Infrastructure Storm Hardening strategies[3]
- Smart Grid (SG) and Distribution Automation (DA) initiatives[4]

The scope of each item was outlined in separate tasking documents supplied to GE. The exact text of each task is provided below:

1.1.1 BPU Scope - Electric Distribution Infrastructure Storm Hardening

Review and evaluate data contained in the Major Event reports submitted by New Jersey's Electric Distribution Companies (EDC) in accordance with N.J.A.C. 14:5-8.8 going forward from July 2011 through June 2013 [source documents were supplied by the BPU]. Assess the extent of infrastructure damage caused by wind, trees, flying debris, inland flooding, storm surge and the individual costs of restoration.

1. *Identify industry initiatives applicable to electric distribution infrastructure storm hardening; prepare a synopsis of those initiatives currently implemented or under consideration by other states, including their estimated implementation costs, and expected improvements in system reliability; i.e. reductions in CAIDI and SAIFI or other benefits. Given the assessments made in No. 1 above, identify and recommend storm hardening initiatives deserving consideration by the New Jersey EDCs.*
2. *Evaluate the cost to EDCs of implementing the following programs:*
   a. *Annual vegetation management inspections of overhead transmission and distribution facilities as compared to inspections required under the current standards set forth by the North American Electric Reliability Corporation (NERC) and N.J.A.C. 14:5-9 et. seq.*
   b. *Annual ground based inspection programs for overhead transmission and distribution facilities, including poles and other support structures, as compared to the current system of regularly scheduled inspections of utility poles and overhead equipment.*
3. *Evaluate the costs and benefits of implementing the following requirements:*
   a. *Construction of new and/or relocation of existing electric substations above the 100-year floodplain;*
   b. *Providing adequate back-up power for central offices and substations;*
   c. *Design and deployment of particular types of transmission and distribution conductors and structures (specifically wood, concrete, and steel for new construction or upgrade/expansion of existing lines); and*

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[3] New Jersey Board of Public Utilities Consultant Tasking Document, *Electric Distribution Infrastructure Storm Hardening*, Dated January 10, 2013, Submitted to GE on February 13, 2014

[4] New Jersey Board of Public Utilities Consultant Tasking Document, *Smart Grid (SG) And Distribution Automation (DA) Review, Analysis and Recommendations*, Dated December 3, 2013, Submitted to GE on February 13, 2014

d. *Building underground transmission and distribution lines, including new construction, expansion of existing lines, or rebuilds.*

1.1.2 BPU Scope - Smart Grid (SG) and Distribution Automation (DA) Review

1. *Perform a review of the submissions by the Electric Distribution Companies (EDC) relating to SG and DA plans under items BPU63 and 65 including the following:*

   a. *The overall results of the EDC pilot programs, including any results that should be implemented statewide, if applicable;*

   b. *The degree and measure to which each of the EDCs SG and DA systems currently in-place as set forth in their SG/DA plans (BPU-65) meets the definition of SG/DA as set forth in the Energy Independence and Security Act of 2007 (EISA 2007). This assessment should be used to gage the needs for expansion of their SG/DA systems;*

   c. *The extent and/or depth of current or pending SG and DA plans described in the submissions, performed in the context of the current results of the USDOE SG Investment Grant Program and the EPRI Smart Grid Demonstration programs. The review shall include any recommendations for revisions to the current plans;*

   d. *The timeframe and costs to implement the SG and DA plans submitted under BPU-65;*

   e. *Develop additional questions that Board Staff should be asking of the EDCs regarding these initiatives in particular as it related to the recent results of the USDOE and EPRI SG programs.*

2. *In the review and evaluation of the EDC SG and DA pilots (BPU-63) and plans (BPU-65), GE should prepare a synopsis of the current industry practices and trends regarding SG and DA in the northeast and mid-Atlantic region, and the potential to integrate these practices into the current EDC SG and DA programs. This should include an evaluation of the cost to the EDCs of implementing the integration of these current industry practices and trends throughout the State of New Jersey.*

3. *In addition, GE shall evaluate the impacts of changes in technology such as the use of advanced meters and the implementation of smart grid/distribution automation would have on the resiliency of the electric distribution system and on the reliability of the EDCs service following a natural disaster such as a hurricane, Derecho, or northeaster. This evaluation shall include the cost to the EDCs of implementing the integration of that technology including advanced meters for improved resiliency and reliability throughout the State of New Jersey.*

1.2 Study Approach

GE Energy Consulting has drawn upon its expertise in distribution planning, engineering and operations, its many years of experience working with electric utilities, and the breadth and depth of the GE Energy Management business to address the major tasks outlined above.

GE's approach is a synthesis of engineering judgment and critical analysis to review and assess the reports and plans submitted by the EDCs in New Jersey. Publicly available information from other utilities, state commissions, government agencies, industry organizations, and consultants was used to develop context, identify reference cases, and establish best practices.

The original work scope was substantially impacted by the limited data and information that were made available to GE, apart from the EDC major event reports and Smart Grid/distribution automation plans (SGDAP). Therefore it was agreed between the BPU and GE that the project work should focus on assessing what was available from the EDCs, developing a framework for analysis where data is not available, and supplementing the evaluation with information from other states and utilities (where appropriate).

Following a presentation to the Commissioners on August 1, 2014 in Trenton, NJ, the Board expressed a strong desire for "actionable items" that would lead to improved reliability and resiliency. Consequently, GE proposed to develop "strong recommendations with commissioner-level appeal" for each section of the original scope, expand the scope where needed to fulfill the request, and to supplement each recommendation with a roadmap for implementation (as far as possible).

The original scope items (listed in Section 1.1 above) and the subsequent findings and key recommendations developed from the work are discussed in the following four (4) chapters:

Chapter 2: Assessment of EDC Major Event Reports (MERs) and Reporting Requirements – addresses the scope outlined in Infrastructure Storm Hardening, Subtask 1, and makes recommendations for improvements to the EDC reporting requirements (data, and presentation).

Chapter 3: Distribution Storm Hardening Initiatives - addresses the scope outlined in Infrastructure Storm Hardening, Subtasks 2, 3c and 3d, and makes recommendations for vegetation management, ground-based inspection, pole/hardware upgrades, and undergrounding initiatives to improve reliability and resiliency.

Chapter 4: Substation Hardening Strategies – addresses the scope outlined in Infrastructure Storm Hardening, Subtasks 3a and 3b, and makes recommendations for substation flood avoidance, flood control and backup power strategies to improve resiliency.

Chapter 5: Review of Smart Grid and Distribution Automation Initiatives - addresses the scope outlined in SGDAP Review, Subtasks 1-3 and makes recommendations for Smart Grid and DA initiatives that would improve reliability and resiliency.

2 ASSESSMENT OF EDC MERS AND REPORTING REQUIREMENTS

The objective of this section as assigned by the BPU is as follows:

Review and evaluate data contained in the Major Event reports submitted by New Jersey's Electric Distribution Companies (EDC) in accordance with N.J.A.C. 14:5-8.8 going forward from July 2011 through June 2013 (see source documents); Assess the extent of infrastructure damage caused by wind, trees, flying debris, inland flooding, storm surge and the individual costs of restoration.[7]

N.J.A.C. 14:5-8.8 (the MER Rule) requires that electric utilities submit a report within 15 days of a "major event," and includes a list of the items that should be included in that report. The specific requirements of the rule are listed below:

1. *The EDC shall, within 15 business days after the end of a major event, submit a report to the Board, which shall include the following:*
    a. *The date and time when the EDC's storm or major event center opened and closed;*
    b. *The total number of customers out of service over the course of the major event over four hour intervals, identified by operating area or circuit area. For purposes of this count, the starting time shall be when the storm center opens and the ending time shall be when the storm center closes. Regardless of when the storm center is closed, the EDC shall report the date and time when the last customer affected by a major event is restored;*
    c. *The number of trouble locations and classifications;*
    d. *The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance;*
    e. *A timeline profile of the number of company line crews, mutual aid crews, non-company contractor line and tree crews working on restoration activities during the duration of the major event;*
    f. *The total number of people assigned to each of the categories in (5.) above;*
    g. *A timeline profile of the number of company crews sent to an affected operating area to assist in the restoration effort;*
    h. *The total number of people assigned to (7.) above.*
2. *The EDC shall continue to cooperate with any Board request for information before, during and after a major event.*

[7] New Jersey Board of Public Utilities Consultant Tasking Document, *Electric Distribution Infrastructure Storm Hardening*, Dated January 10, 2013, Submitted to GE on February 13, 2014

2.1 Review of Major Event Reports Pursuant to NJ 14:5-8.8

As agreed with the BPU, the scope of this task was confined to reviewing the individual EDC Major Event Reports (MERs) supplied to GE by the BPU. The goals were to: (1) evaluate the usefulness of the MERs for providing insight into the causes of infrastructure damage and costs of restoration; and (2) suggest recommendations for improving the quality and consistency of the reports.

The following reports (supplied to GE by the BPU) were reviewed as part of this task:

1. Jersey Central Power & Light Company Report to the New Jersey Board of Public Utilities, "*Response to Hurricane Sandy Outages, October 29, 2012 – December 10, 2012*." (8 pages)
2. Jersey Central Power & Light Company Report to the New Jersey Board of Public Utilities, "*Response to Snow Storm Outages October 29, 2011 – November 7, 2011*" Dated November 30, 2011 (10 pages)
3. Jersey Central Power & Light Company Report to the New Jersey Board of Public Utilities, "*Response to Hurricane Irene Outages, August 27, 2011 – September 5, 2001*." dated September 27, 2011 (10 pages)
4. Atlantic City Electric Company – "State of New Jersey Major Event Report October 28 to November 5, 2012 – Hurricane Sandy" dated November 28, 2012 (22 pages)
5. Atlantic City Electric Company – "State of New Jersey Board of Public Utilities Major Event Report June 30 – July 8, 2012 Derecho" dated July 27, 2012 (23 pages)
6. PSEG Services Corporation "Final Report to the BPU Major Event Superstorm Sandy / Nor'Easter October 27 – November 15, 2012" dated February 14, 2013 (39 pages)
7. PSEG Services Corporation "Final Report to the BPU Major Event Superstorm Irene August 27 – September 4, 2011" dated October 28, 2011 (35 pages)
8. Rockland Electric Company "*Revised Major Events Report- October 28-November 10, 2012*" dated February 1, 2012 (7 pages)
9. Rockland Electric Company "*Major Events Report- August 28- September 4, 2011*" dated September 22, 2011 (4 pages)
10. Rockland Electric Company "*Major Events Report- October 29- November 6, 2011*" dated December 8, 2011 (4 pages)

2.1.1 Customer Outages

The NJ 14:5-8.8 Rule data requirements are designed to elicit information that informs the Board about the number of customers inconvenienced. The Rule currently requires EDCs to report the "*total number of customers out of service over the course of the major event over four hour intervals, identified by operating area or circuit area*." However, the Rule does not explicitly specify the format for reporting, and does not require raw data to be submitted in four-hour increments. Raw data and a consistent format would enable more efficient post-event analysis of the magnitude of the event, the impacts on customers, and the duration of those impacts. A few excerpts from EDC major event reports are given below for illustration.

JCP&L

JCP&L's major event reports include charts showing the number of customers out of service in each operating district throughout the event. A separate chart is provided for each operating district. Examples of these charts from JCP&L's Hurricane Sandy MER and Hurricane Irene MER are shown in Figure 2-1 and Figure 2-2. The chart for Hurricane Irene (Figure 2-2) overlays customer outages with customers restored by hour. Although both charts are responsive to the rule's requirements, no raw data are provided to accompany the charts.

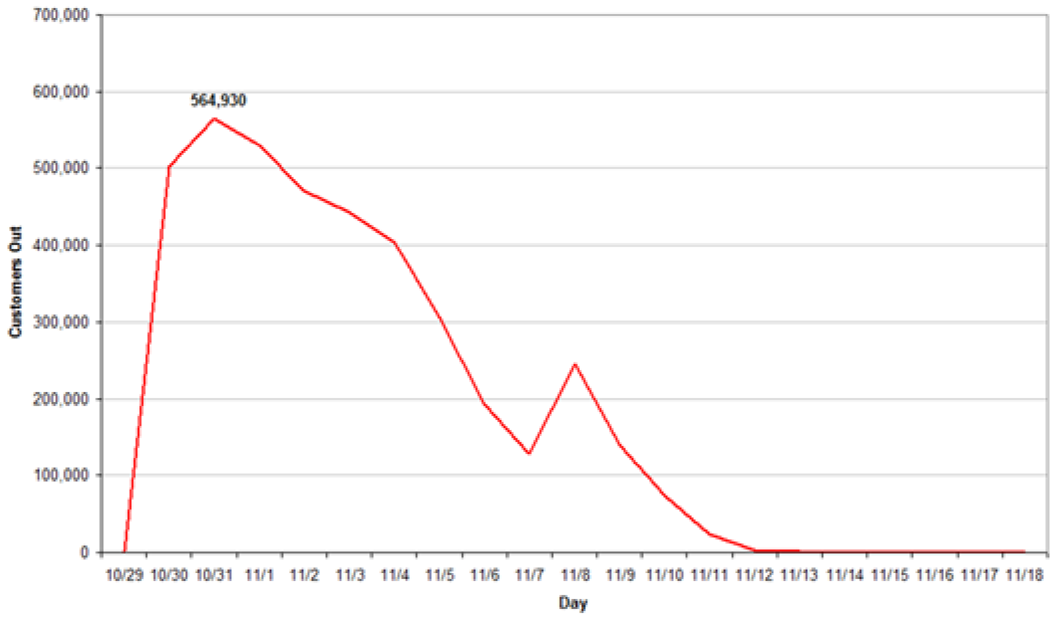

Figure 2-1 JCP&L (CNJ) customers out of service plot – Hurricane Sandy

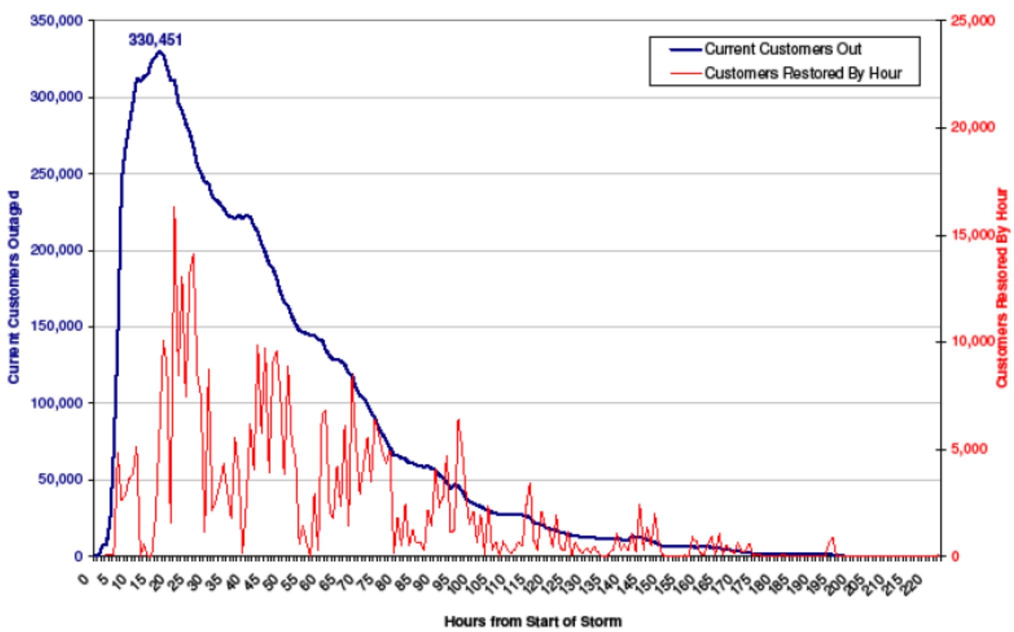

Figure 2-2 JCP&L (CNJ) customers out of service plot – Hurricane Irene

ACE

Atlantic City Electric's report for Hurricane Sandy contains a consolidated chart of customer outages during the event with a trace for each district and one for the region (see Figure 2-3). In addition, ACE provides an accompanying table of outage totals in PDF format (Table 2-1). This allows more efficient post-event analysis (as opposed to than not having the data), but the PDF data format requires some manipulation.

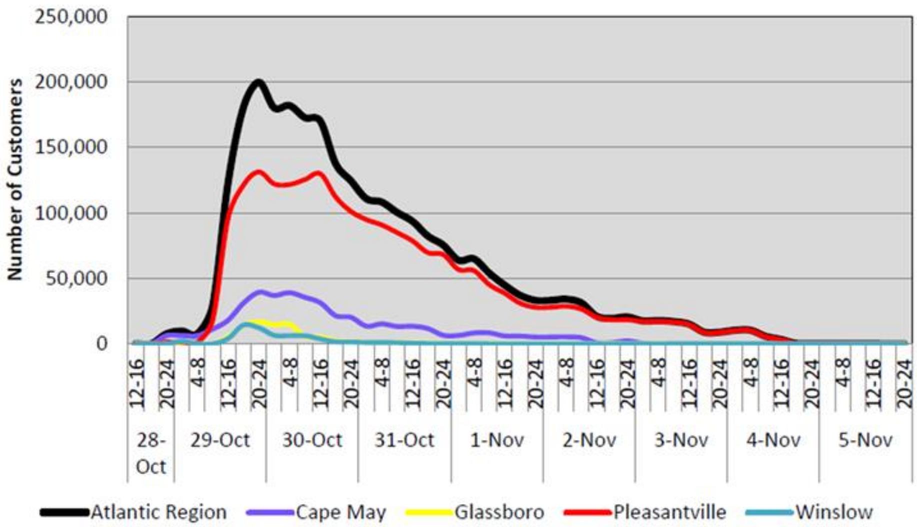

Figure 2-3 ACE customer outages by Atlantic region and district Hurricane Sandy

Table 2-1 ACE customers outage data by Atlantic region and district - Hurricane Sandy

Appendix A

Customer Outages During Storm						
Day	Hour	Total Atlantic Region	Cape May	Glassboro	Pleasantville	Winslow
10/28/2012	12-16	0	0	0	0	0
	16-20	55	6	21	28	0
	20-24	7,723	6,270	205	1,246	2
10/29/2012	0-4	9,686	6,228	152	1,311	1,995
	4-8	7,701	6,220	180	1,249	52
	8-12	29,592	11,275	41	18,260	16
	12-16	123,243	18,037	5,314	95,751	4,141
	16-20	180,614	31,103	13,942	121,259	14,310
	20-24*	199,742	39,340	16,945	131,212	12,245
10/30/2012	0-4	180,197	36,950	14,589	122,120	6,538
	4-8	181,940	39,029	14,939	121,663	6,309
	8-12	172,716	35,527	5,579	125,429	6,181
	12-16	170,154	31,373	5,193	129,817	3,771
	16-20	137,598	21,529	2,292	112,169	1,608
	20-24	124,393	20,237	1,679	101,066	1,411
10/31/2012	0-4	110,848	13,537	1,357	94,885	1,069
	4-8	108,245	15,237	1,151	90,800	1,057
	8-12	100,374	13,264	1,216	84,962	932
	12-16	93,567	13,459	971	78,620	517
	16-20	82,375	11,660	731	69,690	294
	20-24	75,415	6,581	496	68,142	196
11/1/2012	0-4	63,793	6,442	435	56,749	167
	4-8	64,924	8,307	434	55,976	207
	8-12	53,987	8,368	319	45,217	83
	12-16	44,860	6,051	122	38,639	48
	16-20	37,140	5,907	88	31,097	48
	20-24	33,217	5,224	71	27,884	38

PSE&G

PSE&G's reports on Hurricanes Sandy and Irene as well as the October 2011 snowstorm include charts summarizing the customer restoration timeline for the entire company, as well as by division. However, in contrast to the charts from JCP&L and ACE, PSE&G's charts are cumulative and the data are parsed into two traces: customers interrupted by time increment; and customers restored by time increment (see example in Figure 2-4). PSE&G also did not provide any raw data to accompany the plots as ACE did. To put PSEG's response into context with JCP&L and ACE, Staff would need to estimate the interruption and restoration data from the chart, then net out the restorations to get a comparable number of customers out of service during each 4-hour interval.

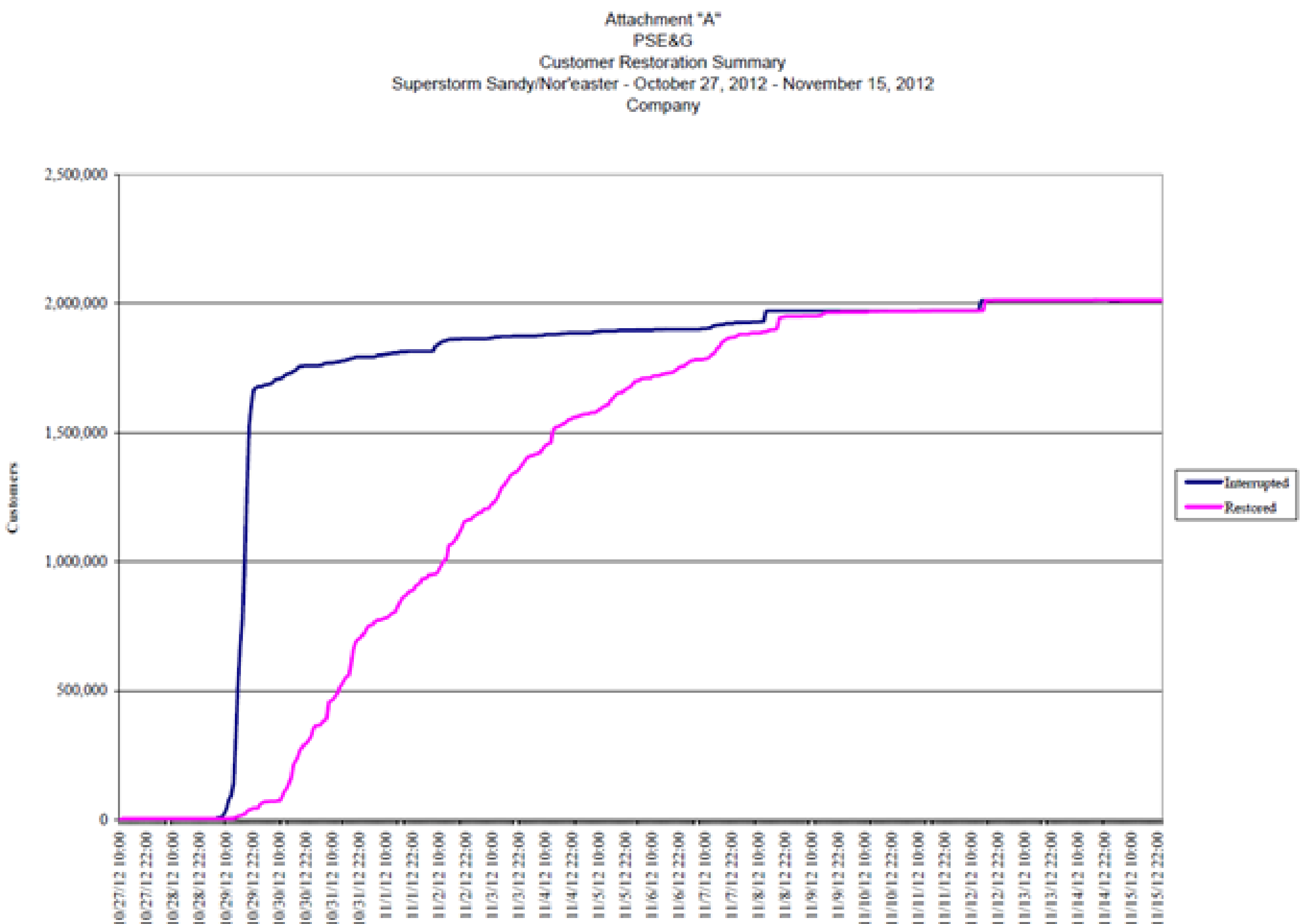

Figure 2-4 PSE&G customers interrupted and restored during Hurricane Sandy

RECO

Rockland Electric Company's major event reports provide the required customer outage data by time increment in tabular form in PDF file format. No plots are provided. Table 2-2 below shows the submission for Hurricane Sandy. The highlighted line indicates the time at which 90% of customers where restored (10/30/12 6:00 PM). Converting these PDF data tables to Excel would require copying the PDF data, pasting in Excel, converting the text to data, and performing multiple manual manipulations to get the single strip of customers out of service during each 4-hour interval.

Table 2-2 RECO customers affected, restored, without service during Hurricane Sandy

Time Period	Customers Affected	Customers Restored	Customers Remaining
10/28/12 6:00 PM	0	0	0
10/28/12 10:00 PM	0	0	0
10/29/12 2:00 AM	927	109	818
10/29/12 6:00 AM	1173	109	1064
10/29/12 10:00 AM	2518	453	2065
10/29/12 2:00 PM	16337	746	15591
10/29/12 6:00 PM	55969	2014	53955
10/29/12 10:00 PM	57816	2014	55802
10/30/12 2:00 AM	58084	2014	56070
10/30/12 6:00 AM	58183	2014	56169
10/30/12 10:00 AM	58968	2936	56032
10/30/12 2:00 PM	58978	3613	55365
10/30/12 6:00 PM	59326	4167	55159
10/30/12 10:00 PM	59336	5081	54255
10/31/12 2:00 AM	59472	5417	54055
10/31/12 6:00 AM	59473	5417	54056
10/31/12 10:00 AM	59473	5417	54056
10/31/12 2:00 PM	59478	5417	54061
⋮	⋮	⋮	⋮
11/2/12 10:00 PM	61320	24787	36533
11/3/12 2:00 AM	61320	25222	36098
11/3/12 6:00 AM	61322	25222	36100
11/3/12 10:00 AM	61382	27822	33560
11/3/12 2:00 PM	61819	29019	32800
11/3/12 6:00 PM	61970	33602	28368
11/3/12 10:00 PM	61970	34404	27566
11/4/12 1:00 AM	61970	35280	26690
11/4/12 5:00 AM	61970	35770	26200

The time scale is broken to show the duration of the event.

There is a discontinuity in the timescale at 11/4/12 1:00 AM, where the increment from the previous time is 3 hours instead of 4.

Individually, these EDC MERs are responsive to the letter of the rule's requirements in that they give the Board the "total number of customers out of service over the course of the major event over four hour intervals, identified by operating area or circuit area." However, collectively the MERs lack consistency on what types of data are presented and how they are displayed or submitted. This limits the usefulness of the data for post-event analysis and for benchmarking storm restoration performance across EDCs. However, as Figure 2-5 from the BPU Hurricane Irene report shows,[8] it is possible to prepare a comparative chart of customer outages for all EDCs based on the data in the MERs. A consistent data format, however, would better facilitate this exercise for the BPU Staff.

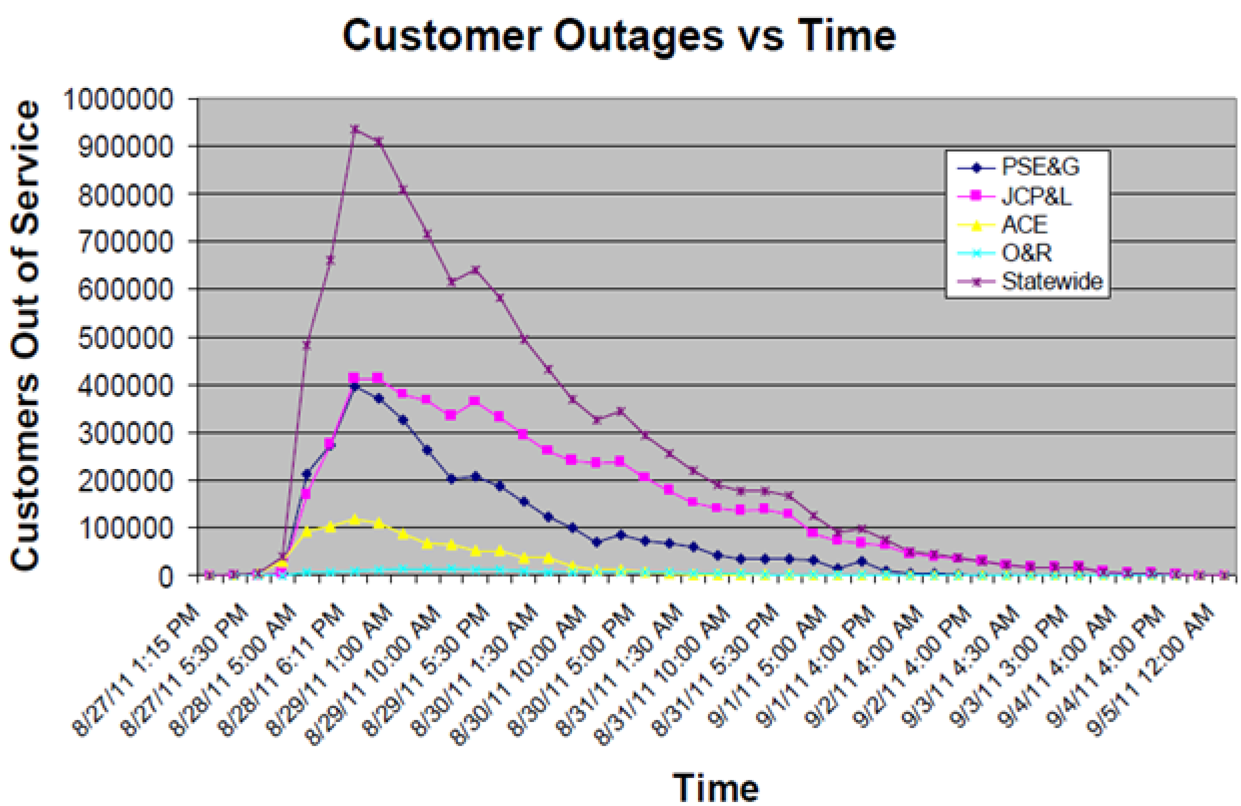

Figure 2-5 Customer outages vs. time for all EDCs during Hurricane Irene from BPU report

2.1.2 Infrastructure Damage

The MER Rule (NJ 14:5-8.8) does not explicitly require EDCs to report infrastructure damage and causes. However, it does require the EDCs to report "*The number of trouble locations and classifications*." This requirement is interpreted differently by the various EDCs and consequently the data available in the MERs on infrastructure damage and causes vary considerably. In some cases, the information provided by EDCs is so limited that it is not particularly useful for gauging the system's resilience to major storms.

JCP&L

JCP&L's MERs for Hurricanes Sandy and Irene and the October 2011 snowstorm contain no information on the infrastructure damage caused by the storms (broken poles and crossarms, miles of wire replaced, damaged transformers, etc.). However, the attachment for Hurricane Irene provides additional useful information.[9] The MERs also do not provide any information on the

[8] From BPU Hurricane Irene Report, Reprinted in Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships, August 9, 2012, Page 46

[9] JCP&L's Attachment No. 1 for Hurricane Irene contains additional information on the number of circuits damaged, wire-down orders, blown fuse orders, broken poles, and crossarms, and miles of wire replaced. The attachment also

causes of customer outages. Under "trouble locations and classifications" in the main body of the MER, JCP&L reports the Trouble Orders and Outage Orders by operating district (see the excerpt from JCP&L's Hurricane Sandy MER in Table 2-3 below).

Table 2-3 Excerpt from JCP&L Hurricane Sandy Major Event Report

	Trouble Orders*	Outage Orders**
JCP&L - Central NJ Region	29,742	13,339
JCP&L - North NJ Region	30,038	10,696
Total JCP&L	59,780	24,035

**Trouble orders represent orders in the outage management system where there is a report of some trouble issue in the field. This does not represent locations in the field nor does it represent customers that were out of power because more than one order may pertain to a single location, and multiples of customers may be affected by a single order.*

***Outage orders represent orders in the outage management system where customers are reported out of lights. This does not represent locations in the field because more than one order may pertain to a single location.*

ACE

Similar to JCP&L, ACE's Hurricane Sandy MER gives no information on infrastructure damage or causes of customer outages. Under "trouble locations and classifications", ACE refers to an Appendix table that lists the Outage Orders and Non-Outage Orders in each district for each four-interval during the storm restoration period (see Table 2-4 below).

Table 2-4 Excerpt from ACE's Hurricane Sandy Major Event Report

Number of Trouble Locations and Type									
		Cape May		Glassboro		Pleasantville		Winslow	
Day	Hour	Outage Orders	Non-outage Orders	Outage Orders	Non-outage Orders	Outage Orders	Non-outage Orders	Outage Orders	Non-outage Orders
10/28/2012	16-20	4	2	6	1	7	3	1	2
	20-24	9	2	9	3	8	5	2	1
10/29/2012	0-4	7	3	8	1	11	5	4	1
	4-8	9	3	6	2	7	8	5	1
	8-12	19	8	14	12	58	14	9	4
	12-16	40	10	41	22	172	46	36	9
	16-20	107	32	149	54	414	134	158	42
	20-24	175	55	246	83	523	215	245	62
10/30/2012	0-4	178	60	328	107	548	231	271	70
	4-8	204	56	369	121	590	260	268	71
⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮	⋮

contains a narrative covering preparedness and drills, storm tracking, damage, assessment, communications, and other topics.

PSE&G

PSE&G's major event reports provide the most detailed data on equipment damage of any of the EDCs. Each of the MERs reviewed for PSE&G (Hurricane Irene, Hurricane Sandy, October 2011 snowstorm) included the following sections with information on infrastructure damage and causes:

- Operating Report – includes a list of PSE&G substations affected by the storm with details on impacts and mitigation measures.
- Trouble Locations and Classifications – lists Outside Plant damage to primary, secondary and services conductors, transformers, poles and trees, and Inside Plant damage to substations: breakers, auxiliary switches, control and protection systems, batteries, battery chargers, etc. Table 2-5 below is an example from a PSE&G MER Trouble Locations and Classifications section.
- Incidents – describes interruption incidents to major loads and substations, their causes and restoration.

Table 2-5 Trouble Locations and Classifications from PSE&G's Hurricane Sandy MER

TROUBLE LOCATIONS AND CLASSIFICATIONS

Outside Plant damage locations are listed below:

69/26-kV –	355
13/4-kV –	2,504
Transformers –	1,022
Secondaries –	N/A
Services –	8,330
Poles –	2,500
Trees –	48,000
Total –	62,711

Inside Plant damage locations are listed below:

Switching Station/Substation	High Level Damage Assessment
Bayway Substation	26 and 4 kV breakers and control cabinets and voltage regulator controls damaged.
Linden Switch	138kV breakers and control cabinets, battery chargers and relay equipment damaged.

Although compliant with the requirements of the rule, some of the data are of limited use to inform policymaking. For example, knowing 1,022 transformers were damaged would be more useful if the causes of the damage were known. If damage causes were specified, and magnitudes were provided, the Board could direct and support remediation where it would be most effective.

RECO

RECO's MERs for Hurricanes Sandy and Irene and the October 2011 snowstorm do list the causes of customer interruptions, but do not provide specific information on the infrastructure that was damaged by the storms. Under "trouble locations and classifications", RECO reports the number of "no power incidents" and the number of customers affected, and provides a breakdown of the incidents by cause. Table 2-6 below shows an excerpt from RECO's Hurricane Irene MER. This information is useful in that it identifies the major causes of interruptions to RECO's customers (trees), and can help the utility and policymakers target resources in a cost-effective manner. In addition to this information, data on the extent of infrastructure damage would also be useful for post-event analysis. For example, Table 2-6 shows that equipment failure led to 52 interruptions affecting 3,668 customers. However, the MER does not provide any further detail on the specific type of equipment that failed (line, pole, tranfomer, etc.) or why it failed. Additional useful data would include: the number and type of poles broken and/replaced; the miles and type of conductor replaced; number of transformers damaged; substation equipment damaged; etc.

Table 2-6 Trouble Locations and Classifications from RECO's Hurricane Sandy MER

There were 1,569 "no power incidents" affecting 34,824 customers throughout the RECO Service Territory over the course of the storm. These outages were broken down, by cause and customers affected, as follows:

- Tree Contact – 891 interruptions, affecting 27,254 customers;
- Equipment Failure – 52 interruptions, affecting 3,668 customers;
- No Cause Found - 145 interruptions, affecting 2,276 customers;
- Customer Problem – 70 interruptions, affecting 70 customers; and
- Unknown* - 411 interruptions, affecting 1,556 customers.
  **Unknown requires further analysis and review to determine the specific cause.*

2.1.3 Cost of Restoration

The N.J.A.C. MER rule as disseminated does not require the EDCs to provide specific information on the costs of restoration (which consists of labor cost and equipment cost). Each of the EDCs have submitted crew deployment data in response to the Rule's requirements, but none of the EDC submissions contain sufficient data on the infrastructure damaged and replaced to allow meaningful estimates of the equipment cost. The MER Rule does require detailed information on the number of company line crews, contractor crews and mutual aid crews working the storm, the number of people assigned to work, and timeline profile of the crew deployment during the restoration effort. This staffing information may allow one to estimate (roughly) the labor costs during the restoration effort, but critical information on equipment replacement and other associated costs would not be captured in these estimates.

Since New Jersey requires EDCs to submit a report within 15 days of a major event, it is likely (and perhaps understandable) that EDCs would not have complete data on the costs of restoration when they submit they report. Cost data may still be pending from other companies involved in the restoration process (contractors, other utilities, vendors), and cleanup and rework might still be ongoing. However, the Board should specifically request the information that is available to the EDCs 15 days after the storm that would give insight into the recovery costs. This includes (in addition to crew data), specific information on the number and type of equipment damaged and replaced.

2.2 Key Findings and Recommendations

The observations and findings with respect to the EDC major event reports are:

- The EDC reports vary significantly in terms of quality and content. NJ 14:5-8.8 does not stipulate a common reporting format. Requirements are open to interpretation and consequently the EDCs submit different data and information to satisfy the same requirement. For example, the requirement to report, "*The total number of customers out of service over the course of the major event over four hour intervals, identified by operating area or circuit area*" results in major event reports with significantly different levels of granularity, making cross comparisons more difficult. Table 2-7 summarizes the content of the EDC MERs with respect to the items that GE was asked to evaluate in this task.

Table 2-7 Comparative Summary of Some Pertinent Information in EDC MERs

	ACE	JCP&L	PSE&G	RECO
Customer Outages	Frequency charts of outages + data table	Frequency charts of outages	Cumulative charts of interruptions and restorations	Data table of customers affected, restored, remaining
Infrastructure Damage	None	For Irene only; in attachment	For T&D and substations	For T&D
Cause of Damage	None	None	For stations (flooding) and major loads	None
Recovery Costs	None	None	None	None

- Additional reporting requirements to address EDC's pre-event preparedness would enhance the BPU's ability to assess overall response to events. Additional reporting requirements specifying how the EDC's track storms, predict damage, mobilize the workforce stage crews and assess damage would give the BPU (and utilities) more insight into the drivers for a particular response and where improvements can be made.
- EDC reports (in general) should include more granular geographical information of outages, and interrupted customers by class and priority, along with the MW impacted. These data could be useful in future assessments to determine economic impact, effectiveness of past corrective actions, and to identify where repetitive failures are indicative of deeper root causes.
- The MERs could benefit from enhanced content and standardized format. It should be possible for the BPU and the EDCs to agree on common format, charts and descriptive data that would clearly describe EDC storm response in the MER.
- Reports should include performance metrics and benchmarking against previous major storms.

These observations lead to the following key recommendation to the BPU:

Recommendation MR-1: Upgrade EDC MER requirements

a. ***Enhance standard reporting requirements to collect additional data.***
b. ***Provide data collection and reporting templates to drive consistency.***

c. Develop performance standard and assessment scorecard for post-event analysis.

The Board has expressed a need to assess the extent of damage to grid equipment, with causes of damage assigned (e.g. wind, trees, flying debris, inland flooding, storm surge, poor design, etc.). An assessment of the EDC major event reports for several recent storms (see Section 2.1) has revealed that the necessary information does not exist in the reports, or that the information is inconsistent and not granular enough to be meaningful.

Over the course of this study, one of the key observations is that *higher fidelity data needs to be gathered so that more granular analyses can be performed*. This would enable targeted application of distribution hardening initiatives, substation hardening strategies, and Smart Grid and distribution automation technology.

Across the EDCs, there are significant differences in service area characteristics and customer needs/expectations. Even within an EDC territory, differences can be observed in the characteristics of operating areas and districts, and may exist even at the feeder and segment levels. For example, a feeder/segment that is heavily treed and serves a critical load (such as a fire station) can be differentiated from another feeder/segment with a cleared corridor serving residential loads. A clear picture of the storm experiences of customers on these feeders/segments is essential to understanding the effectiveness of hardening initiatives, strategies, or technologies. Therefore, the overarching goal of this recommendation is to facilitate collection of more data, in a consistent manner, and at a sufficiently granular level to enable comparisons, benchmarking, and performance assessment via scorecard methods.

Possible implementation steps for this recommendation include:

1. Define consistent data collection templates for the restoration effort and equipment tracking (see examples in Figure 2-6 and Figure 2-7). Figure 2-6 is an example template to collect customer outage data, unserved load and crew deployment by circuit over the timeline of the storm. Figure 2-7 is a proposed template to collect infrastructure damage, causes, and equipment replacements by circuit. These templates can be issued and received as Excel.csv files to minimize BPU staff data manipulation. As discussed earlier, consistent data at a more granular level is necessary to justify and evaluate the targeted application of various storm hardening measures (which will be discussed further in subsequent chapters).
2. Define standardized comparison graphs and charts to facilitate clear understanding of damage extent and root cause (see examples in Figure 2-8, Figure 2-9 and Figure 2-10). With consistent, granular data facilitated by Step 1 above, useful charts and graphs can be plotted to compare restoration profiles of major storms (Figure 2-8), cross-compare EDC performance for a given storm (Figure 2-9) and display major causes of infrastructure damage and customer interruptions (Figure 2-10).
3. Develop a scorecard methodology for assessment of EDC storm response performance (e.g. MD Performance Standard and NY DPS Utility Scorecard).

As part of this recommendation, the BPU should prescribe performance standards for the EDCs and develop a methodology to assess and track the performance of individual EDCs during storms.

One example of a state with a storm performance standard is Maryland which established specific SAIFI and SAIDI metrics for each utility from 2012 to 2015 (as GE is aware that many other states do). However, the Maryland Standard also included major event performance in its metrics. Among other things, MD Rulemaking (RM) 43 regulations:[10,11]

- Require at least 92% of sustained outages during normal events be restored w/in 8 hrs;
- Require at least 95% of sustained outages during "Major Events" of < 400,000 or 40% of customers be restored within 50 hrs.

Based on this Maryland standard, some of the New Jersey EDCs would not have been compliant during Sandy (based on the chart in Figure 2-9). However, the precise thresholds for the major event restoration targets in New Jersey should be based on the historical performance of the New Jersey EDCS and expectations for quality of service. Nevertheless, this is a concept that New Jersey can apply to its EDCs.

New York State has adopted a quantitative tool, or "scorecard," for use by utilities and the NY Public Service Commission (PSC) to assess utility storm restoration performance (Case 13-E-0140).[12] The scorecard is intended to help the NY PSC evaluate utility performance in the aftermath of storms. The NY PSC scorecard:[3]

- Assigns metrics and points into 3 categories: Preparation (150 pts.), operational response (550 pts.) and communications (300 pts.);
- Utilities must submit specified data on per-event basis w/in 30 days of restoration for use by staff to score each outage for each utility.

Consistent with the theme of "*higher fidelity data for more granular analyses*", if the EDCs were to provide consistent and comparable data in an easy-to-use form, this would enable the BPU to consider implementing a scorecard approach.

[10] EEI, "Before and After the Storm – Update: A Compilation of Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency," March 2014

[11] Public Service Commission Of Maryland, Administrative Docket RM43, Order No. 85817, Revisions to COMAR 20.50 – Service Supplied by Electric Commission Electric Companies – Proposed Reliability And Service Quality Standards, Issue Date: September 3, 2013

[12] State Of New York Public Service Commission, Case 13–E-0140 - Proceeding on Motion of the Commission to Consider Utility Emergency Performance Metrics, Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages, Issued and Effective December 23, 2013

Circuit #2

Time/Date 4-Hr Intervals		Hrs Since Start	Customers Out	MW Unserved	Company Crews Deployed	Contractor Crews Deployed	Mutua Aid Crews Deployed
29-Oct-12	2:00	0	2,300	10.2	58	17	0

Circuit #1

Time/Date 4-Hr Intervals		Hrs Since Start	Customers Out	MW Unserved	Company Crews Deployed	Contractor Crews Deployed	Mutua Aid Crews Deployed
29-Oct-12	2:00	0	500	2.8	22	5	0

Total Area

Time/Date 4-Hr Intervals		Hrs Since Start	Customers Out	MW Unserved	Company Crews Deployed	Contractor Crews Deployed	Mutua Aid Crews Deployed
29-Oct-12	2:00	0	27,000	187	1200	200	0
29-Oct-12	6:00	4	59,000	248			
29-Oct-12	10:00	8	99,000	782			
29-Oct-12	14:00	12	142,000				
29-Oct-12	18:00	16	190,000				
29-Oct-12	22:00	20	195000				
30-Oct-12	2:00	24					
30-Oct-12	6:00	28					
30-Oct-12	10:00	32					
30-Oct-12	14:00	36					
30-Oct-12	18:00	40					
30-Oct-12	22:00	44					
31-Oct-12	2:00						
31-Oct-12	6:00						
31-Oct-12	10:00						
31-Oct-12	14:00						
31-Oct-12	18:00						
31-Oct-12	22:00						
1-Nov-12	2:00						

Figure 2-6 Sample template for collecting timeline data by circuit

Circuit #2

		Damage Cause						
Equip ID*	Desc	Wind	Trees	Ice	Snow	Flooding	Replacement Type	Date Replaced
2569845A25	Class C Wood pole		x				Class B Wood	10/31/2012

Circuit #1

		Damage Cause						
Equip ID*	Desc	Wind	Trees	Ice	Snow	Flooding	Replacement Type	Date Replaced
2569845A25	Class C Wood pole		X				Class B Wood	10/31/2012

* Equipment ID tied to size, cost, location, design, type, age

Figure 2-7 Sample data template for collecting equipment damage and causes by circuit

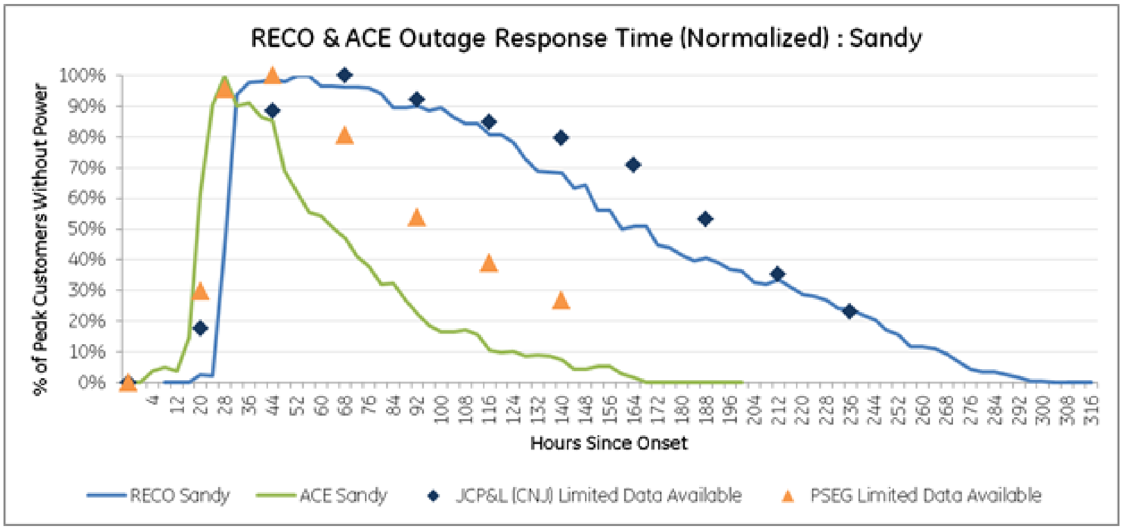

Figure 2-8 Normalized chart of EDC storm response to Hurricane Sandy

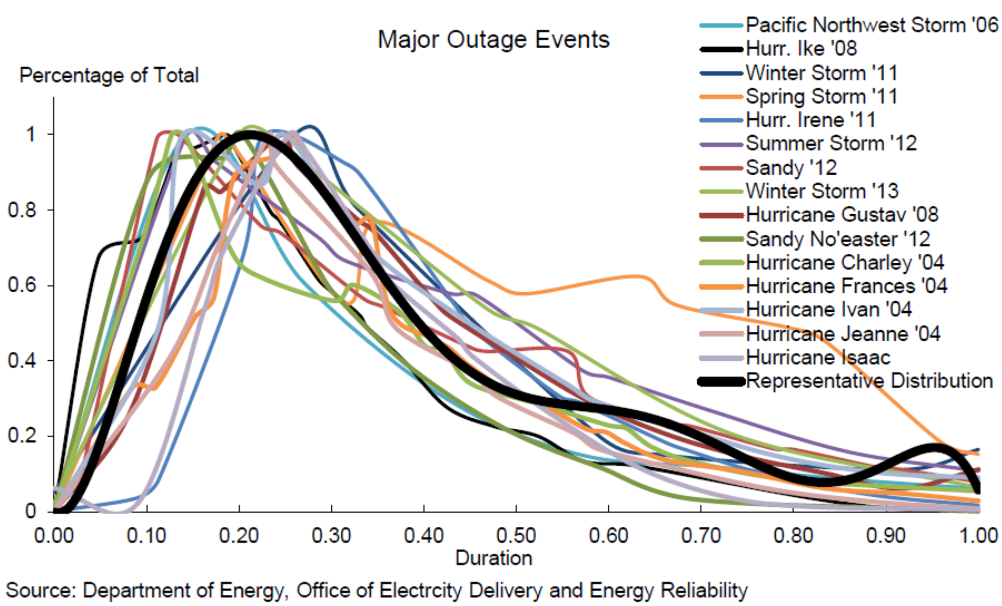

Figure 2-9 Normalized chart of historical storm restoration profiles from the DOE

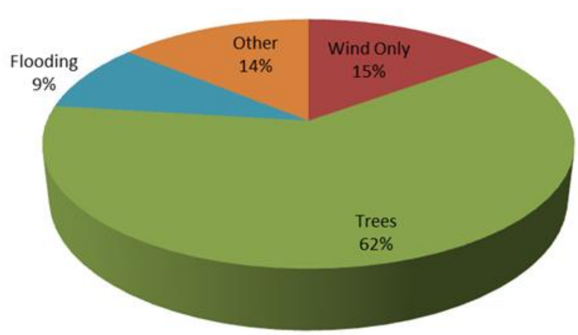

Figure 2-10 Generic example of causation chart showing pole failures by cause

3 DISTRIBUTION STORM HARDENING INITIATIVES

Storm-hardening activities aim to reduce the impact of future storms by planning, designing, and maintaining the electrical infrastructure to make it less susceptible to physical damage (from high winds, falling trees, flood, etc.), and to make it easier to reestablish service after storm-related outages. Hardening is only one aspect of the total storm resilience and response strategy. Other critical elements include: preparation, training, drills, storm tracking, damage prediction, damage assessment, staging, and communications, (see Appendix B).

Within the sphere of storm hardening, some of the more common activities include: vegetation management, undergrounding lines, upgrading poles and hardware, and more frequent inspection and maintenance of distribution structures and equipment. This section will discuss each of these four hardening initiatives in detail and make recommendations to the BPU for adoption of pertinent measures.

3.1 Vegetation Management

Discussions of distribution storm damage often begin (and sometimes end) with trees. Trees account for a large majority of storm outages, mostly because of falling trees and branches breaking overhead equipment, or limbs brushing against energized lines causing contact faults. After a major ice storm in November 2006, Ameren sustained significant damage to its overhead facilities in Missouri and Illinois, because tens of thousands of trees – some of them 100 years old and over 80 feet tall – fell on poles and lines. Approximately 520,000 customers in both states lost power for up to eight (8) days. Just prior to the 2006 ice storm, the Missouri Public Service Commission staff had released a report on Ameren's performance during a July 2006 windstorm; the report acknowledged that, "*the density of large old-growth trees represents a risk to utility service following storms with high winds or heavy ice*."[1] Not surprisingly, the utility was roundly criticized for not having trimmed the trees more frequently and fully to minimize the outages. In response, Ameren maintained that because the utility is very constrained (as are most utilities) in how they can trim trees, no amount of trimming would have made a difference.

Along distribution circuits, utilities are typically only allowed to trim trees to the limits of their easements, which is typically 10 to 15 feet from the centerline of the pole. In Ameren's case, they could not legally remove trees, even those planted within their easements. According to remarks by their CEO, there are literally millions of large trees planted within a few yards of overhead distribution lines, and countless more close enough to lines to knock them down in a bad storm. "*When a 60-foot tree which is 40 feet from a power line falls on that line, no amount of tree trimming is going to prevent an outage*."[2]

1 Report on Ameren UE's Storm Outage Planning and Restoration Effort Following the Storms on July 19 and 21, 2006, Case No. EO-2007-0037 Missouri Public Service Commission Staff, November 17, 2006

2 From a Webcast: Media Update on the Nov. 30 Ice Storm and Restoration, Dec. 13, 2006, 1:00 a.m. CT, Opening Remarks: Gary L. Rainwater, Ameren Chairman, CEO and President, http://www.ameren.com/Outage/ADC_OpeningRemarks.asp

This sentiment was also expressed by the Missouri Public Service Commission in its July 2006 assessment of Ameren's performance during the windstorm. In the same report, the MO PSC noted:

> *"It must, however, be emphasized that even if all of the trees in AmerenUE's service territory were trimmed per current procedures immediately before these storms hit the St. Louis area, much of the damage observed would have still occurred. Significant damage to AmerenUE's system was caused by trees and tree limbs that would not be removed by AmerenUE's current trimming programs or are not on AmerenUE's right-of-way."*

3.1.1 Trees and Storm Damage in NJ

Data from the EDC major event reports supplied to GE by the BPU clearly demonstrate that downed trees and tree-related damage were a major issue during the October 2011 snowstorm, as well as hurricanes Sandy and Irene.

After the October 2011 snowstorm, JCP&L reported:[3]

> *"The damage from this unusually early and heavy snow storm was particularly severe, due to the tree density of JCP&L's Northern Region. An overwhelming majority of JCP&L's Northern Region includes some of the most heavily treed parts of New Jersey. JCP&L's vegetation management clearance standards for distribution right-of-ways do not contemplate the potential impact of foliated, snow-laden tree limbs and JCP&L's vegetation management rights do not extend to off right-of-way trees, a considerable amount of which collapsed from the heavy snow during this storm onto adjacent distribution lines resulting in a significant number of broken poles and conductors."*

Similarly, PSE&G also noted the following:[4]

> *"The heavy, wet snow that fell on trees that had not yet lost their leaves caused trees to be uprooted and fall and for limbs to break and fall, causing extensive damage to PSE&G's Outside Plant, especially in PSE&G's three northern Divisions, Central, Metropolitan and Palisades. The fallen trees and broken limbs created driving hazards and created delays in reaching trouble locations throughout PSE&G's service territory."*

These observations are supported by a FERC report on transmission outages during the October 2011 snowstorm in New England and the Mid-Atlantic states. The report stated that:[5]

> *"… off-right–of-way tree fall-ins accounted for about half of the storm's transmission line outages, and nearly 75% of all confirmed vegetation-caused outages."*

During hurricanes Irene and Sandy all EDCs in NJ reported significant damage and delays in restoration due to downed trees.

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[3] JCP&L Report to the New Jersey Board of Public Utilities, Response to Snow Storm Outages October 29, 2011 – November 7, 2011, November 30, 2011

[4] PSE&G's Revised Final Report to the BPU Major Event Wet Snow Storm October 29 – November 6, 2011, January 3, 2012

[5] "Report on Transmission Facility Outages during the Northeast Snowstorm of October 29-30,2011" prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, May, 2012.

Some of the relevant comments from the EDC major event reports are given below:

> *"Restoration efforts were also challenged due the large number of downed trees" – JCP&L Hurricane Irene MER*[6]
>
> *"Restoration efforts were challenged by thousands of downed trees, fallen branches and other debris as well as flooding from heavy rain ... As in last year's Hurricane Irene and the October 2011 Snowstorm experiences, away from shore areas, trees generally were a primary source of damage and outages, including, importantly, off-right-of-way trees." – JCP&L Hurricane Sandy MER*[7]
>
> *"In the Atlantic City region, the severe rain and strong wind gusts caused heavy flooding, with falling tree limbs and debris. ACE personnel staffed the state and local emergency management agencies and emergency operations centers and the Company coordinated with fire departments and departments of transportation to address safety hazards and clear roads blocked by trees and downed wires." – ACE Hurricane Sandy MER*[8]
>
> *"There were 1,239 'no power incidents' affecting 75,122 customers throughout the RECO Service Territory over the course of the storm ... The preliminary data indicates: Tree Contact - 614 interruptions, affecting 53,230 customers" – RECO Hurricane Sandy MER*[9]

The October 2011 storm experiences in particular, highlight the fact that off-right-of-way trees are a major problem for utilities in NJ. This is consistent with the experience of utilities in other states, as evidenced by the AmerenUE case discussed earlier in Section 3.1.

3.1.2 Impact of Off-Right-of-Way Trees

One of the best ways to significantly reduce the number of tree-related outages is to identify and remove trees that could fall on distribution lines during a storm. But this could mean removing all trees over a certain height within striking distance of the lines – literally millions of trees in some service territories alone. Not only do utilities lack the necessary authority to remove trees outside the right-of-way (ROW), but in many cases they are actively opposed by landowners, neighborhood groups and municipalities, even for trimming and removing trees *within* the clearance zone. In one recent example, a picturesque town in Florida actively refused to allow Progress Energy Florida (now part of Duke) to trim back massive oak trees which were a prominent feature of the town. GE Energy Consulting was contracted to assess the impact of the vegetation encroachment on the reliability issues experienced by the town, and the potential for automation to improve reliability. The pictures below are a sample of what was observed during a casual drive along several medium voltage lines.

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6 JCP&L Report to the New Jersey Board of Public Utilities, Response to Hurricane Irene Outages August 27, 2011 – September 5, 2011, Submitted September 27, 2011, Page 5.

7 JCP&L Report to the New Jersey Board of Public Utilities, Response to Hurricane Sandy Outages October 29, 2012 – November 18, 2012, Submitted December 10, 2012, Page 4.

8 Atlantic City Electric Company – Major Event Report Pursuant to N.J.A.C. 14:5-8.8 for the Major Event of October 28 to November 5, 2012 – Hurricane/Superstorm Sandy, Submitted November 28, 2012, Page 2.

9 Rockland Electric Company Revised Major Events Report - October 28-November 10, 2012, Submitted December 4, 2012, Page 4.

Figure 3-1 Sample of vegetation issues within distribution clearance zone in a Florida town

Although this may be an extreme case, it nevertheless illustrates that tree-trimming is a very sensitive issue for many parties, because it impacts reliability, resiliency, aesthetics, wildlife and the environment. In this context, state service commissions set minimum standards for vegetation management and utilities typically adopt and adapt the standards to suit their specific needs. In New Jersey, rule N.J.A.C. 14:5-9 (described in Section 3.1.3) sets the requirements for vegetation management, including minimum inspection and trim cycles.

Trimming trees within the clearance zones maintains and improves reliability under “normal” operating conditions, but storm experiences have shown that it may have less impact on reducing the number of outages in major storms. For example, the Missouri PSC Staff report on the July 2006 windstorm concluded that “w*hile the vegetation management programs of AmerenUE can improve day-to-day reliability, in their current form, they will not significantly reduce the severity of outages following major storms.*[10]

JCP&L’s experience during the October 2011 snowstorm, as well as other EDC storm experiences, confirm that mitigating the impact of danger trees outside the right-of-way (off-ROW danger trees) has the most potential (from a vegetation management perspective) to reduce storm damage, decrease the number of customer outages, and speed up restoration time. Based on these observations, GE makes the following four (4) recommendations to the Board:

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[10] Report on Ameren UE’s Storm Outage Planning and Restoration Effort Following the Storms on July 19 and 21, 2006, Case No. EO-2007-0037 Missouri Public Service Commission Staff, November 17, 2006

Recommendation DH-1: Track off-ROW trees; predict and report outages, damage, ETR

***Track off-ROW trees** posing risk of outages; **predict** and report associated **damage**, number of customer interruptions, and restoration time by danger tree.*

This recommendation enables a tree-centric view of the impact off-ROW trees. Most EDC forestry departments already routinely identify danger trees within the clearance zone, but not all keep data on off-ROW danger trees. In a report commissioned by the BPU on the EDCs' performance during the major storms of 2011, only ACE reported keeping off-ROW statistics.[11] The causes of outages during both blue-sky days and storm situations (wind, flying debris, flood, trees, animals, etc.) are typically captured in databases for post-event analysis. These databases may or may not be integrated with other data sources within the utility. JCP&L, for example, uses GE's PowerOn OMS application *"to create a database of causation data, including classification of preventable or non-preventable vegetation-related outages."*[12] This type of information, especially on preventable (due to trees within the ROW) and non-preventable (due to trees outside the ROW) tree-related outages, should be included in each EDC major event report, and the extent of infrastructure damage, customer outages, and delays in response due to off-ROW danger trees should also be highlighted. Earlier in Section 2.1.2 it was noted that the N.J.A.C. 14:5-8.8 rule does not require EDCs to report the causes of outages, and therefore only limited information on causation is available in the MERs. This recommendation is consistent with the recommendation in Section 2.2 to improve the EDC MERs.

However, Recommendation DH-1 goes beyond simply tracking and reporting off-ROW danger trees. Predicting the plausible impact of existing danger trees on reliability and resiliency is the next logical step.

The application of advanced analytics to solve traditional utility planning and operation problems is a current trend in the industry, and is one that has tremendous potential in vegetation management.

Existing and emerging technology can aggregate data from disparate utility sources, correlate circuit information with weather data, outage data, and vegetation data to:

1. Calculate the expected number and duration of outages specifically due to off-ROW danger trees (reliability impact); and
2. Project the level of storm damage and impact on time of restoration (resiliency impact).

Figure 3-2 below shows the data sources and framework for a tool under collaborative development by GE Energy Management and utility partners. One of the features of the development plan is the calculation of risk factors that would predict the probability of outages or safety violations at the line segment (or span) level for sustained outages and momentary outages. The framework enables aggregation of data from: different utility data sources such as Outage Management Systems (OMS) and Vegetation Management (VM) databases; external sources such as LiDAR, weather and satellite feeds; and data from public sources such as social media, Google Earth, and government databases. These data sources are integrated into a common analytic application layer running fault analyses, reliability calculations, and damage assessment

[11] Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships, August 9, 2012

[12] Based on Direct Testimony of Ralph C. Hilmer, JCP&L, Before the BPU, Exhibit JC-16

algorithms. Such a framework would enable a utility to predict the impact of danger trees on the reliability and resiliency of nearby customers.

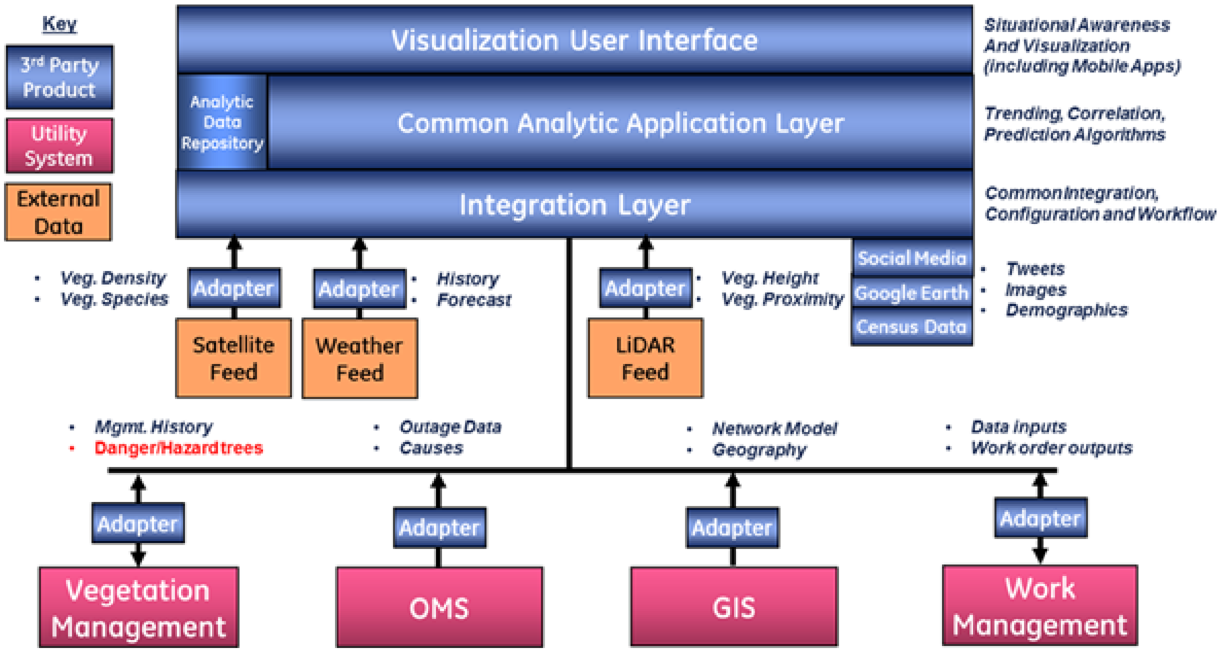


Figure 3-2 Data and architectural framework for VM advanced analytic Application

Critical pieces of data to predict the impact of danger trees on reliability and resiliency include:

- Location of danger trees overlaid on a system model (from GIS, OMS, VM sources);
- Probability of occurrence and likely intensity of storm events, ice, wind, snow, etc., (from history and forecast);
- Number of expected storm days/year (from weather history).

With these data, the general methodology below can be used to predict the impact of danger trees:

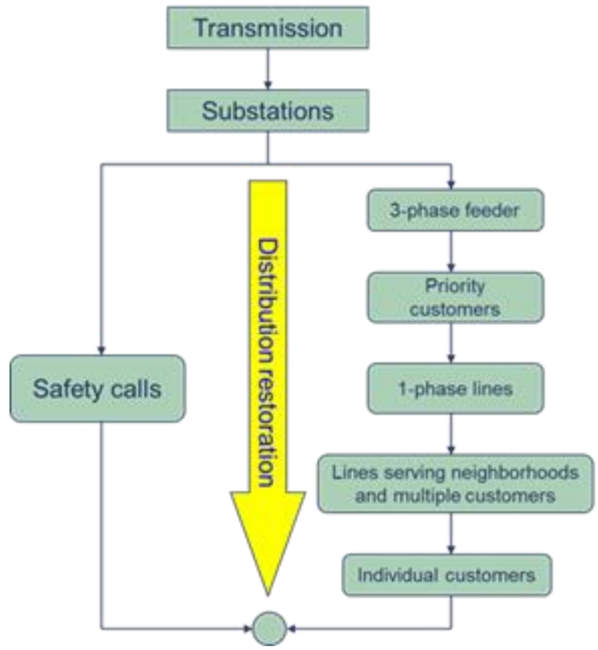
1. Apply a fault to the system model at the location of each danger tree;
2. Compute the number of interrupted customers and total unserved load (MW);
3. Estimate worst-case damage due to the event (broken pole, downed wire, damaged transformer, insulators); report using standard damage assessment format;
4. Simulate the restoration process and estimate the time to restore customers (ETR);
5. Calculate and report total unserved energy (MWh) by customer class;
6. Prorate and report the number of interrupted customers and total unserved MW/MWh by the probability of weather events.

The output of this analytic process is a relational database with information about the impact of each danger tree on its circuit segment, on nearby segments, and on customers in the immediate area. This would allow EDCs to aggregate the impact of multiple danger trees and compute the overall degradation in service for groups of customers.

Recommendation DH-2: Segment customers; calculate/report hours out due to trees

***Segment* customers by restoration priority; *calculate* and report an *estimate of hours out of service* due to tree damage during normal weather *for each customer*.**

This recommendation enables a customer-centric view of the impact of off-ROW trees. Customers who are served by circuits adjacent to off-ROW danger trees will eventually be interrupted by tree-related events, whether during storms or blue-sky days. However, not all customers are equally impacted.



For example, customers with a sectionalizing device between their location and the danger tree can potentially be restored faster than customers on the same switchable segment as the tree. Also, high priority customers such as hospitals, nursing homes, emergency responders, persons with life-support equipment are typically targeted for earlier restoration during outages (see restoration priority flow chart to the right).

Recommendation DH-2 is a logical extension of the previous Recommendation (DH-1) and will give the BPU insight into the degradation in service for different categories of ratepayers due to off-ROW trees.

Data needed to implement this recommendation are derived from the output of the previous recommendation (DH-1), along with additional information on the customer type.

In order to estimate the hours out of service for ratepayers, the following pieces of information are needed:

- Type of customers, criticality and location overlaid on a system model (from OMS, CIS);
- Length of circuit outages due to off-ROW danger tress (from calculations in Recommendation DH-1;
- Probability of storm events, ice, wind, snow, etc., and intensity (from history and forecast);
- Number of expected storm days/year (from weather history).

With this data, the general methodology below can be used to estimate hours out of service due to tree damage during normal weather for each ratepayer:

1. Categorize customers in the affected area by level of exposure, remediation measure, and restoration priority;
2. Allocate the duration of circuit outages due to off-ROW tree fault events (from Recommendation DH-1) to the affected customers;
3. Aggregate the number of hours of service interruption per year for each customer due to events;

4. Pro-rate hours out of service due to tree damage by the probability of weather events and report results.

Recommendation DH-3 Communicate estimates; provide mechanisms for reporting

***Communicate estimates to customers* and provide convenient mechanisms for customers to report danger trees (e.g. via Twitter feeds).**

This recommendation will enable EDCs to use the insight from recommendations DH-1 and DH-2 to drive customer engagement, and incorporate crowd-sourcing into utility operations. When the power goes out, customers typically want to know three things: *Does the electric company know my power is out*? *When will the power be back on*? *What caused the outage*?[13] Failure to provide adequate information can lead a customer from being "understanding", to becoming "frustrated and disillusioned" with their service.

According to a J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study, the more information customers receive about outages the more they are satisfied.[14] As the chart to the right shows, among customers who called to report an outage, those who were given four or more points of information about the outage gave the utility significantly higher scores for power quality & reliability (PQ&R), than customers who were given one point of outage information.

Points of information may include a message about an outage in the area, a message that the customer's power specifically is out, information on the cause and extent of the outage, the time to restore power, instructions on what to do if power is not restored by a certain time, and other useful pieces of information.

Providing customers with information about the historical and likely future impact that hazards such as off-ROW danger trees can have on their power service is a good public relations practice, in that it serves to:

1. Reduce the customer's shock/anxiety about major outages;
2. Motivate customers to report potential danger trees to the utility to improve neighborhood resiliency prospects; and
3. Encourage landowners and/or municipalities to remove the offending trees, or at least permit the utility to do so.

Proactive information can be provided in newspapers, bill inserts or door hangers, for example.

[13] Brent A. Stegner, AEP, "*Service Restoration Communications and Customer Satisfaction*", DistribuTECH Conference, February 4-6, 2007

[14] Jordan Silvertrust, "Rising prices, higher expectations cause decline in utility customer satisfaction: J.D. Power and Associates," Electric Light & Power Magazine, 2007

Today, most utilities maintain an Internet portal that includes a storm center where customers can report outages and get outage information and estimated restoration times. All four NJ EDCs maintain active storm center portals on their websites. Table 3-1 below presents the attributes of the NJ EDC storm center web portals for comparison. Key features compared in the table include:

- Prominent Storm Center/Outage Link – prominence of storm center/outage reporting link on the utility homepage; is it more than twelve-point text in a long sidebar menu?
- No. of Clicks – the number of clicks or menu selections needed to navigate from the home page to the storm center or outage information portal;
- Report Outage w/o Login – capability to report outages through online form submission, without the need to login to a customer account;
- Storm Alert Sign-Up – ability to sign up for individualized outage alerts from the storm center via texts, emails or push notifications;
- Social Media – ability for customers to interact with the utility via social media such as Twitter, Facebook, Instagram, LinkedIn, etc.;
- Mobile App – ability for customers to download mobile apps to receive alerts and report outages;
- Report Danger & Upload Photos – ability for customers to report potentially dangerous situations to the utility and upload photos on storm portal or via mobile app (apart from social media);
- Outage Data/Maps – customer capability to view system outages in thematically shaded (interactive) map and/or data form from the portal; and
- ETR – ability for customers to get estimated times of restoration for outages for their area or for their service specifically.

Table 3-1 Comparison of NJ EDC Storm Center Web Portals (as of September 2014)

Utility	ACE	JCP&l	PSE&G	RECO
Prominent Storm Center/Outage link	Yes	Yes	No	Yes
No. of clicks	1	1	1	1
Report outage without login	Yes	Yes	No	Yes
Storm alert sign-up	Yes	Yes	Yes	Yes
Social media	Yes	Yes	Yes	Yes
Mobile app	Yes	Yes	No	Yes
Report danger & upload Pics	No	No	No	No
Outage data/maps	Data & Map	Data & Map	Data & Map	Data & Map
ETR	Yes	Yes	Yes	Yes

All the NJ EDCs provide at least one mechanism for customers to report outages, but none currently give customers the ability to report dangerous situations (such as a danger tree or leaning pole) *and* upload photos. While they all maintain social media accounts (mostly Facebook and Twitter), the accounts are not typically used to collect outage and danger information. In fact, at least one EDC, PSE&G, cautions customers that *"Social media should not be used to report outages or emergencies."*[15]

With this knowledge about the potential impact of danger trees at their fingertips, customers may be motivated and should be encouraged to use Social Media, Mobile Apps, SMS, Email, and Storm Portals to report suspected danger trees in their neighborhoods and, importantly, upload photos to the utility. Appropriate key words or hashtags can be used to alert the utility. A Tweet for example, may read:

> *"Hey @PSEGdelivers this old tree will fall over my line soon #DangerTree"*

This mechanism can be extended to rotten poles, damaged insulators, downed wires, and a host of other issues that the utility would like to be made aware of. The key is to provide customers with actionable information and a mechanism for them to report incidents.

Recommendation DH-4: Grant EDCs authority to remove off-ROW danger trees

Where justified, <u>grant</u> EDCs <u>the authority to remove danger trees</u> outside the clearance zone.

A desirable (and likely) outcome of increased customer awareness and vigilance (resulting from Recommendation DH-3) is the pressure on landowners and municipalities to (1) remove off-ROW danger trees with high potential to impact reliability and resiliency, or (2) allow utilities to remove or treat them. The picture to the right is a good example of an off-ROW tree with high potential to bring down the electrical infrastructure during a storm event and interrupt service to multiple customers. This may be a case where the utility can justifiably be given the right to remove a tree outside its corridor for societal benefit reasons.

As discussed earlier in Section 3.1.1, trees, specifically off-right-of-way trees, accounted for an overwhelming majority of the damage in NJ during the October 2011 snowstorm and hurricanes Irene and Sandy. This is not unique to NJ as many states and jurisdictions across the U.S. face this same problem. The EPP Report to the BPU states the following with regard to PSE&G:[16]

> *"On a daily basis, 80-85% of tree related outages are from trees out of ROW. In 2011, PSE&G started to devote 10-15% of its budget to danger trees. The trees are identified by contractors / crew leaders during the course of their normal work. PSE&G will ask the homeowner for permission to trim and many times the homeowner obliges."*

[15] https://www.pseg.com/home/customer_service/outage_info/stay_connected.jsp

[16] Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships, August 9, 2012, Page. 124

This observation is corroborated by a FERC report on transmission outages during the October 2011 snowstorm, which stated that for the NJ EDCs:[17]

> *"… off-right–of-way tree fall-ins accounted for about half of the storm's transmission line outages, and nearly 75% of all confirmed vegetation-caused outages."*

In a more general sense, the EPP Report observes that:[18]

> *"Across the utility industry, between 20 to 50% of all unplanned distribution outages are tree-related, with a majority caused by tree failures outside the ROW.[19] The EDC have no authority to remove trees that are not in the ROW unless they receive permission from the property owner."*

Based on these observations, the case can be made that if utilities are empowered via eminent domain to remove, trim or treat potentially hazardous trees outside the energized corridor, blue-sky reliability and storm resiliency would improve. It is difficult to develop a transfer function between the level of danger tree removal and improvement in reliability without the data and analysis proposed earlier in Recommendation DH-1. However, the case is compelling enough that several states and jurisdictions currently have regulatory decisions or legislative proposals that give utilities more latitude to address off-ROW trees. A sampling of these includes:[20]

CA Case R08-11-005: Regulatory decision conditionally authorizes utilities to turn off power supply to property owners who block VM activities around overhead power lines.

CT H.B. 5551: Legislative proposal to (1) allow companies that provide electric or telephone services to acquire by eminent domain a tree or shrub that is on or adjacent to an existing right-of-way or easement held by the company if the company determines that such tree or shrub would cause an interruption in the delivery of such service due to the condition of the tree or in the event of a storm accompanied by winds of hurricane force, snow or ice, and (2) make technical changes.

IL H.B. 3884: Legislative proposal provides that it shall be unlawful for any person to plant restricted vegetation within 20 feet of an electric utility pole or overhead electrical conductor located within the State; provides that any restricted vegetation planted, whether by a person or by natural means, within 20 feet of an electric utility pole or overhead electrical conductor located within the State shall be subject to removal.

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[17] "Report on Transmission Facility Outages during the Northeast Snowstorm of October 29-30,2011" prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, May, 2012.

[18] Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships, August 9, 2012, Page118

[19] Guggenmoos, S., Effects of Tree Mortality on Power Line Security. Journal of Arboriculture, 29(4), July 2003

[20] EEI, "Before and After the Storm – Update: A Compilation of Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency," March 2014

It is recommended that the BPU and the State of NJ initiate and support the appropriate legislative process to grant utilities the authority to remove off-ROW trees with highest impact on ratepayer reliability and (by extension) resiliency. Output from the analytic process in Recommendations DH-1 and DH-2 can be used to rank danger trees based on impact to ratepayers.

The ability (or lack thereof) of the NJ EDCs to remove danger trees, trim or treat them is an important part of the story and must be documented along with the impacts. With this information in hand, the BPU can develop jurisdiction-specific approaches for extending utility authority and work with the legislature to propose and pass appropriate bills.

3.1.3 Vegetation Management Inspection and Maintenance Cycles

Section 14-5-9.4 of the NJ Vegetation Rule prescribes the maintenance cycle for vegetation management (VM). The pertinent excerpts are:[21]

> *14:5-9.4 (a) "An EDC shall perform an annual visual inspection of all energized conductors that are associated with a transmission line, to determine whether vegetation management is needed."*
>
> *14:5-9.4 (b) "An EDC shall perform vegetation management on vegetation that is close enough to pose a threat to its energized conductors at least once every four years."*

The NJ vegetation rule does not specifically impose an annual inspection cycle for distribution facilities, but for transmission it clearly mandates annual inspection for energized conductors (ground-based where possible).

The explicit requirement for distribution entities is to perform vegetation management (VM) at least every four (4) years. For such VM programs, the rule lays out the minimum activities which include pruning, removal, control, inspection, R&D, and public education. Furthermore, N.J.A.C. 14-5-9 allows each EDC to develop its own vegetation management standards and guidelines (within bounds), and to prioritize work based on the following criteria:

- The extent of the potential for vegetation to interfere with the energized conductor;
- The voltage of the affected energized conductor; and
- The relative importance of the affected energized conductor in maintaining safety and reliability.

Among the minimum standards that EDCs are asked to comply are the vegetation management requirements set forth in the North American Electric Reliability Corporation (NERC) Transmission Vegetation Management Standard.

The latest version of the NERC Standard, FAC-003-2, is generally applicable to transmission lines operated at 200kV or higher, but could apply to transmission lines operated below 200 kV under certain conditions. It does not apply to distribution facilities. The Standard is intended to reduce the risk of cascading outages due to vegetation, i.e. to prevent another widespread event such as the Great Northeast Blackout in 2003. It is not necessarily intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. Having said that, under the

[21] New Jersey Administrative Code, Title 14: Public Utilities, Chapter 5: Electric Service, Subchapter 9: Electric Utility Line Vegetation Management, N.J.A.C. 14:5-9 (2012)

NERC Standard, transmission owners are explicitly required to have a vegetation management program that:[22]

> *1.2 "…specifies a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors"*
>
> *1.3 "… contains an annual work plan which:*
>
> > *1.3.1 Identifies the applicable lines to be maintained*
> >
> > *1.3.2 Identifies the work to be performed and the methods used*
> >
> > *1.3.3 Shows flexibility to adjust to changing conditions and to findings from Vegetation Inspections*
> >
> > *1.3.4 Considers permitting and scheduling requirements from landowners or regulatory authorities"*

Based on the New Jersey Vegetation rule, the EDCs in NJ have developed and adhered to customized vegetation management programs that target improvement in system reliability, but also aim to reduce the amount of damage during major storms and lessen the restoration burden.

3.1.4 Impact of Tree Trimming on System Reliability

Vegetation management programs, particularly tree trimming, are an essential part of any utilities overall strategy to maintain and improve service reliability. The main impact of vegetation patrol and tree trimming is on the failure rate of overhead lines, i.e. the number of times per year that a line experiences an outage that requires reclosing to clear a fault or a crew to be dispatched to repair the line. For example, a line with a sustained failure rate of 0.1/mile/year would be expected to fail once every 10 years for every mile of circuit. The more often a line is maintained, the less likely it is to sustain a fault and cause customer interruptions.

Historical data that can establish the link between trim cycle and line failure are not generally publicly available. Many utilities have these data, but sometimes not in a ready format for analysis, and often lacking the analytics to develop a response surface.

In his well-regarded text on Electric Power Distribution Reliability, R. E. Brown observes that:[23]

> *"In the past tree-trimming programs have attempted to identify appropriate cycle times with every right-of-way being trimmed every 2 to 6 years. [Figure 3 3] shows the impact of cycle time on vegetation failures for a utility in the midwestern US. More sophisticated programs may have different cycle times for main trunks and laterals, and the most sophisticated methods utilize*

[22] NERC Standard FAC-003-2, Transmission Vegetation Management, September 2009, Page 17-18

[23] Richard E. Brown, "Electric Power Distribution Reliability," Second Edition, 2009, CRC Press

reliability-centered maintenance techniques to identify the best cycle times for each right-of-way."

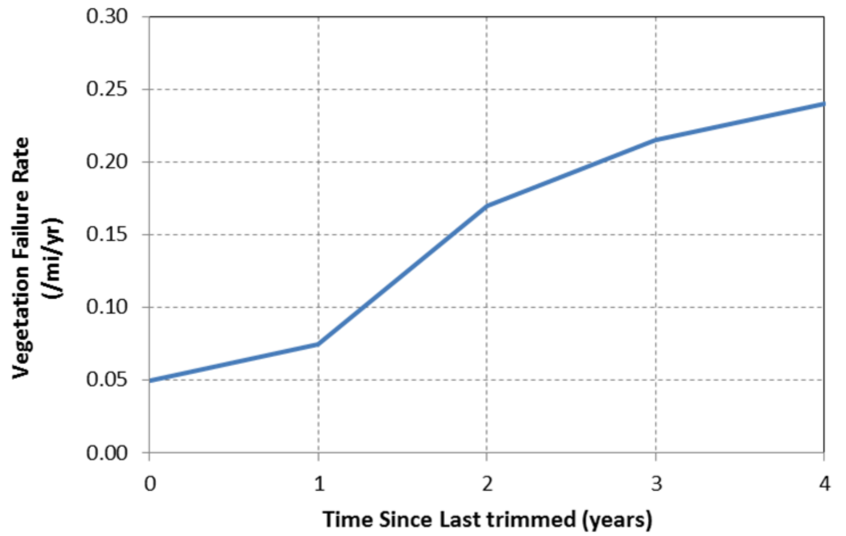

Figure 3-3 Tree Trimming cycle time Impact on OH line Failure Rate for a U.S. Utility

The plot in Figure 3-3 from Brown (2009) demonstrates that for the Midwestern utility, vegetation-related failures increased by nearly a factor of five from the time a right-of-way was trimmed through four years without additional trimming. Equipment failure rates are typically used in reliability assessment models to compute reliability indices by feeder, zone or substation. The most popular of these indices are SAIFI System Average Interruption Frequency Index), and SAIDI (System Average Interruption Duration Index). The definitions SAIFI and SAIDI are given by the expressions below:

$$\text{SAIFI} = \frac{\sum \text{Number of Customer Interruptions}}{\text{Total Number of Customers Served}} \quad /\text{yr}$$

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \quad \text{hr/yr}$$

The precise impact on SAIFI and SAIDI due to a decrease in line failure rate is difficult to predict without knowledge of the circuit layout, customer distribution, and details on the protection and sectionalizing equipment. However, SAIFI is particularly sensitive to line failure rates, so any reduction in the number of overhead line failures would directly reduce the number of customer interruptions (decreasing SAIFI), and by extension also decrease the number of hours of interruption for affected customers (reduce SAIDI). The width of the trim corridor can also have a significant impact on reliability, as measured by SAIFI and SAIDI. This illustrated by the JCP&L case below.

From 2009 to 2011, JCP&L pursued a short-term corridor widening initiative to create additional space between distribution lines and trees, branches and overhang, beyond the 15-feet of clearance wherever it was practical. Because they had been collecting causation data for off-ROW (non-preventable) trees and limbs over time, JCP&L decided that *"there was a significant opportunity* *for reliability improvements if the Company began addressing corridor widening and corridor overhang.”*[24]

Table 3-2 below (based on data in R. C. Hilmer’s testimony before the BPU) summarizes the impact of the extended trimming on (1) customer minutes of interruption (CMI), which is a proxy for SAIDI, (2) number of interruptions, which is a proxy for SAIFI, and (3) number of customers affected, which affects both SAIDI and SAIFI. In all cases except 2009, the customer interruption measures decreased (i.e. reliability improved) relative to the previous year.[25]

Table 3-2 Summary of Impact of JCP&L Corridor Widening Initiative

	2009	2010	2011
Change in customer minutes of interruption (CMI)	-17.5%	-0.30%	-24.6%
Change in number of interruptions	+6.8%	-45.7%	-23.1%
Change in number of customers affected	-32.5%	-0.50%	-48.9%

The preceding data and utility experiences, along with the analytical framework described earlier in Recommendation DH-1, lead to the recommendation below.

Recommendation DH-5: Determine the most cost-effective level of tree-trimming

<u>Determine</u> the <u>most cost-effective level of tree-trimming</u> and optimal corridor width by circuit or segment using vegetation data and other relevant inputs.

Evidence in the EDC major event reports, and other sources (such as the FERC and EPP reports quoted above) clearly show that trees are a common root-cause of reliability and resiliency problems on circuits in New Jersey. However, the state of NJ is quite diverse, and some EDCs are more prone to tree-related outages than others. JCP&L, for example, serves some of the most heavily treed parts of Northern NJ and suffers a disproportionately larger number of tree-related outages per circuit than ACE, which serves a predominantly coastal urban area. However in the EPP Report to the NJ BPU, ACE reports using condition-based maintenance strategies to inform their tree-trimming schedule, while JCP&L reports using cyclic maintenance (See Table 3-3 below from the EPP Report[26]).

Even within a particular utility service area, the need for tree trimming and the extent of trimming can vary significantly by substation area, feeder or even segment. With access to more data than ever before, advanced tools and analytics (such as those described in Recommendation DH-1), it is possible to prioritize and customize VM activities even down to a circuit segment. This would result in optimal use of the VM budget while ensuring that areas that need more attention are addressed appropriately.

[24] Based on Direct Testimony of Ralph C. Hilmer , JCP&L, Before the BPU, Exhibit JC-16, Page 10
[25] The increase in number of interruptions in 2009 was explained by the fact that corridor widening was only on three-phase main sections in 2009, but was also applied to single-phase laterals from 2010 onward.
[26] Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships, August 9, 2012, page 120.

Table 3-3 shows that JCP&L and RECO have a cyclic vegetation management schedule, trimming every four (4) and three (3) respectively. PSE&G also trims generally on a four-year schedule, but reports using a simulation model to determine the priority of the circuit.

ACE, as previously stated, reports using a reliability-centered maintenance (RCM) strategy, where, presumably, the condition, history and importance (reliability impact) of the circuit are taken into account to determine inspection and trimming cycles.

Table 3-3 Vegetation Management Programs and Cycles for each EDC

Vegetation Management Related Data				
	ACE	**JCP&L**	**PSE&G**	**RECO**
Reliability-Centered VM	Yes – Condition Based Maintenance & Reactive Maintenance	Cyclic Maintenance	Model to Determine Priority Circuit & Review Tree Outages Daily	Cyclic Maintenance, Hot Spot Trimming & Review Tree Outages Daily
Danger Tree Program	Yes	Yes	Yes	Yes
Out of ROW Statistics	Yes	Non-Preventable**	No	No
Transmission VM Cycle	4	4	4	3
Distribution VM Cycle	4	4	4	4

Source: EPP Report on Performance of EDCs in 2011 Major Storms

A reliability-centered maintenance strategy for vegetation management was also mentioned in the earlier quote from Brown (2009), and is also recommended in a report submitted to the Public Utility Commission of Texas by Texas A&M University in 2011. The Texas A&M Report states that:[27]

> *"Trimming right-of-way vegetation on a fixed time cycle (e.g. every three years) will seldom achieve maximum reliability at optimal cost when applied uniformly across an entire utility. Rigid adherence to a system-wide fixed cycle for trimming of vegetation near conductors, without respect to local conditions, does not directly address the primary cause of outages, namely tear-down from right-of-way and off right-of-way trees, and blown and/or falling limbs. Furthermore, fixed trim cycles risk focusing too much attention to areas that have a good reliability history and too little attention on areas needing critical, more timely action. However, a targeted fixed-trim period, based on past feeder performance, may be appropriate if adjustments are allowed based on annual variations and diversity in local conditions."*

With the data and applications available today, EDCs can use predictive algorithms, trending, pattern recognition, statistical regression or similar tools to establish the correlation between tree-trimming cycle/corridor width and outages during normal days and storm days. The goal is to make the best use of the VM budget by specifying the appropriate tree-trimming cycle and corridor width at the circuit segment level to maintain or improve reliability and (by extension) resiliency.

[27] Best Practices in Vegetation Management for Enhancing Electric Service in Texas, PUCT Project 38257, B. Don Russell, Texas A&M University, November 11, 2011, page 4.

Critical pieces of data needed to determine the most cost-effective level of tree-trimming and optimal corridor width include:

- Historical line failures and associated customer interruptions;
- Circuit-level reliability indices (SAIDI, SAIF, CAIDI, MAIFI);
- Customers out, restoration times, equipment damaged/replaced during past storms;
- Vegetation density, species, growth rate, location of danger trees relative to circuits.

With this data, the general methodology below can be used to determine the most cost-effective level of tree-trimming and optimal corridor width by circuit segment:

1. Determine statistical correlation between trim cycle and circuit reliability, and between corridor width and circuit reliability;
2. Use the resulting transfer function to adjust circuit failure rates in the reliability model by segment to simulate changes in VM practices;
3. Calculate a response surface to quantify change in segment reliability due to changes in trim cycle and corridor width;
4. Use the results to choose the optimal level of trimming (cycle and width) per segment to achieve a specified expected level of reliability; and
5. Use the expected level of reliability as a sensitivity variable and quantify the incremental change in VM costs.

The key outputs of such an analytic process include:

- Optimal trim cycle and corridor width (within constraints) for each segment to maximize reliability for a given budget;
- Optimal trim cycle and corridor width (within constraints) for each segment to minimize cost for a given reliability target.

3.1.5 Cost of Annual Vegetation Management Inspection

Vegetation inspections or patrols (whether they are ground-based or aerial) are an essential component of every vegetation management program. The goal of the patrol is to look for clearance violations, potential hazards and danger trees. All four EDCs perform inspections of transmission and distribution rights-of-way in a manner consistent with their overall vegetation management program.

For this study, the EDCs were asked (via the BPU) to provide average cost per mile for vegetation patrols. Table 3-4 shows this data.[28] PSE&G and RECO provided both aerial and ground transmission vegetation patrol costs. ACE and JCP&L provided only one aggregated cost figure. The submitted cost per mile for transmission vegetation patrol ranges from a low of $210 (for ACE) to a high $2900 (for JCP&L). For distribution, the cost per mile in Table 3-4 varies from $58 to $575. The wide range in the provided cost data is likely due to differences in how the patrols are conducted as well as

[28] Data requested from the EDCs through the BPU and tabulated as part of this study.

accounting assumptions like whether the cost of repairs conducted during the patrol are included in the vegetation patrol cost.

These data can be compared to vegetation patrol cost data from a Quanta Technology report submitted to the Public Utility Commission of Texas.[29] The report summarizes vegetation inspection programs for Investor-Owned Utilities (IOUs) in Texas and lists costs per mile for vegetation patrol.

Table 3-4 Cost Per Mile for Vegetation Patrols for NJ EDCs

	Transmission Vegetation Patrols	Distribution Vegetation Patrols
ACE	$210	$575
JCP&L	$2,900	$169
PSE&G	$890 (aerial) $491 (ground)	$194
RECO	$185 (aerial) $414 (ground)	$58

In the Quanta Report, the utility cost data also varied widely depending on how the request was interpreted, the nature of the patrol (foot vs. aerial), inspection routine (whether repairs were done during inspection or simply reported), location of the utility, and sourcing and contracting practices.

However, across the board, costs per mile for transmission and distribution patrols in Texas were much lower than costs reported by the New Jersey EDCs, even adjusting for inflation and location.[30] In the Quanta report, costs for transmission vegetation patrol ranged from $17 per mile to $65 per mile, and costs for distribution patrol ranged from $1 per mile to almost $25 per mile.

Considering the wide range in cost per mile data supplied by the EDCs to GE, and the lack of qualifying information, an average cost per mile was used for all EDCs rather than applying the EDC-specific data. The median is a more appropriate measure of statistical average than the mean in this case because it is less impacted by outliers. The median cost for EDC aerial vegetation inspection on transmission lines is almost $540 per mile, and the median cost for ground-based vegetation patrol on transmission lines is about $450 per mile. Therefore (using round numbers), the median cost for transmission vegetation patrol is assumed to be $500 per mile. Similarly, for distribution vegetation patrol, the median cost is approximately $180 per mile. The median inspection cost for subtransmission is assumed to be halfway between transmission and distribution at $340 per mile. Therefore, given the miles of transmission and distribution circuits reported by the EDCs in the EPP Report and other public sources, the average (median) cost for annual vegetation inspection for the EDCs is shown in Table 3-5.

[29] Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs, PUCT Project No. 36375, Richard Brown, Quanta Technology, March 4, 2009.

[30] Average inflation rate of 2.2% can be applied to covert 2009 dollars to 2014 dollars, Average cost of living adjustment of 1.4 applied to adjust TX costs to NJ costs; (See http://www.bls.gov/data/inflation_calculator.htm and http://money.cnn.com/calculator/pf/cost-of-living/)

Table 3-5 Median Cost of Annual Vegetation Inspections for NJ EDCs

	ACE	JCP&L	PSE&G	RECO
Transmission Miles	1,121	2,550	1500	35
Subtransmission Miles	240	1,812	2,393	-
Distribution Miles	10,352	22,670	19,620	853
Annual VM Inspection Cost ($1000)	**$2,505**	**$5,972**	**$5,095**	**$171**

The total cost for annual vegetation inspections for the New Jersey EDCs is approximately $13.7 million. This is about 15% of the 2014 total vegetation management budget estimated for all four EDCs (~$90 million, based on data in the EPP Report).[31] In a survey of DSTAR utility members, the participating utilities reported that their combined overhead inspection budget was between 10% and 15% of their total vegetation management budget.[32]

Even though the total vegetation management patrol cost for the New Jersey EDCs is roughly in this range, it must be noted that the total cost is based on gross averages due to the resolution of the cost data provided by the EDCs and the lack of information about assumptions made in rolling up the VM patrol costs per mile supplied to GE.

3.2 Undergrounding

In the aftermath of major storms, there is almost always a public demand for burying power lines. As far as the public is concerned, this should be a given, since during every storm they are replete with images of power lines brought down by ice, snow, and trees. The potential for improvement in reliability and resiliency combined with the aesthetic benefits have created a powerful argument for undergrounding power lines.

However, the situation is actually more complex than that. Underground (UG) power systems do have fewer outages than overhead systems, but the outages tend to be longer. Converting existing overhead lines to underground circuits does not completely protect customers from storm-related outages, but it does help in situations where vegetation, wind, ice and snow loading are a problem.

On the other hand, depending on the location of facilities, underground systems may sustain more damage than overhead systems. For example, systems located near the coast may suffer significant damage from storm surge (see image to the right).

Many studies have shown that the cost to underground power lines can be 2 to 10 times the cost to build equivalent overhead lines, depending on the location. Consequently many states and utilities have concluded that the benefits of

[31] Table on Page 120 of "Performance Review of EDCs in 2011 Major Storms, Prepared by Emergency Preparedness Partnerships" lists total annual VM budget of ~$75 million in 2011. Costs were escalated at 7% per year to ~$90 million for 2014.

[32] DSTAR Project 13-3, "Survey of Inspection & Maintenance and Thermal Imaging Practices," December 2013, www.dstar.org

widespread undergrounding may not justify the cost. Nevertheless, this is an issue that continues to be discussed and studied by state legislatures, regulatory commissions, municipalities, consultants, and even some utilities to ascertain the costs and benefits undergrounding, and determine how it fits within the portfolio of storm hardening strategies.

There are several excellent references and compendia of studies conducted by various entities. An assessment of publicly available documentation was performed by InfraSource Technology in "*Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion*," submitted to the Florida Public Service Commission per order PSC-06-0351-PAA-EI in February 2007. Another excellent source is the EEI's "*Before and After the Storm: A Compilation Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency*," Updated March 2014. The InfraSource Report in particular outlined the benefits and drawbacks of undergrounding, some of which are summarized briefly below.

3.2.1 Advantages and Disadvantages of Undergrounding

Advantages

Based on industry operating experience and analysis of publicly available studies, some of the potential benefits of undergrounding power lines are summarized below:

- **Improved aesthetics** - The elimination of distribution poles and wires and the possibility of having better tree locations, and improved tree canopies can improve public perception and customer satisfaction, though this is difficult to quantify. However, the fact that new construction in suburban areas is typically URD (underground residential distribution) suggests that there is a perception of value.
- **Fewer outages and momentary interruptions during blue-sky days** - UG cable failure rates are typically half the equivalent OH wire failure rate, and UG cables are less affected by the primary causes of momentary faults on OH lines (lighting, tree contact, animals). Therefore, burying power lines will generally reduce the number of outages seen by customers.
- **Reduced vegetation management costs**- Tree trimming is one of the most expensive activities on distribution systems and the vegetation management budget reflects this. Undergrounding a line would essentially eliminate the need for VM expenditures on that line. According to the EPP Report, the NJ EDCs collectively had a VM budget of over $75 million in 2011. Judging by the rate of growth from 2007 to 2011, the collective budget is likely near $90 million today.[33] Brown (2009) estimates that in extreme cases (very high annual tree trimming costs, approaching $35,000 per mile) the reduction in tree trimming costs can offset about 30% of the cost of undergrounding. For NJ EDCs (with relatively low annual tree trimming costs, averaging about $1,500 per mile), the offset is likely to be less. However, there is still a tangible vegetation management benefit to undergrounding.
- **Less storm damage and potentially faster restoration** - UG systems are intrinsically immune to damage from ice, snow, wind, flying debris and trees during storms. However, they are still subject to flooding and storm surge, especially in coastal areas. Because UG

[33] Assuming annual growth of 7% in vegetation management expenditures from 2011 to 2014.

systems sustain less damaged during storms, they can potentially be restored faster than OH systems which must typically be repaired before restoration can take place.

Other benefits quoted by studies include fewer vehicular accidents, reduced incidents of vandalism, less electrical contact injuries, and improved customer relations due to reduced tree trimming, NIMBY and EMF concerns.

Disadvantages

Some of the potential drawbacks of undergrounding discussed in Brown (2009) include:

- **Regulatory and policy complications** - The cost of undergrounding is substantial and could possibly lead to a rate hike for most customers. This could lead to protracted hearings and discussions that are expensive and distracting to the utility and agencies involved.
- **Environmental impacts** - Whenever construction projects require boring and excavation, there is the potential for soil erosion and disruption to ecologically sensitive areas such as wetlands, streams and rivers.
- **Safety concerns** - Although underground systems are typically safer than overhead systems, UG secondary networked systems, such as those that can be found in central business districts of many cities such as New York, Boston, San Francisco, and Birmingham, are subject to a whole host of issues related to electrical contacts, stray voltage, arcing faults, and manhole explosions. Underground systems are also more exposed to damage from dig-ins and the associated risk of electric contact.
- **Longer duration outages and more customers impacted** - While underground systems have lower failure rates than overhead systems, when they do fail it takes more time to locate and fix the fault. Also because underground systems typically have less sectionalizing equipment than equivalent overhead systems, more customers are exposed to events. In the case of UG secondary networks, when something goes wrong, it's usually big (e.g. entire network collapse).
- **Susceptibility to flooding and storm surge** - Underground systems, especially those in manholes, ducts, and vaults are at risk of being flooded during major storms such as Irene and Sandy. This can cause damage to non-submersible equipment, increase risk of failure and shorten life. Flood waters also slow the response. Storm surge can wreck pad-mounted equipment and erode topsoil, exposing underground equipment as it recedes.

Other documented drawbacks include reduced flexibility for upgrading and reconfiguring circuits, lower emergency overload capability, and higher operation and maintenance costs.

3.2.2 Costs of Undergrounding

Based solely on the documented advantages and disadvantages of undergrounding, a plausible argument can be made for burying power lines. However, when economics enters the equation, it quickly becomes a dominant factor in the decision process.

The most often quoted study on the costs of undergrounding is a 2004 EEI study by Bradley Johnson which was subsequently updated in 2006, 2009, and most recently in 2012 by Kenneth L.

Hall.[34] Table 3-6 and Table 3-7 below summarize data from the 2012 EEI Undergrounding Study that compare the range of costs per mile for new OH and UG transmission construction, and new OH and UG distribution construction, in urban, suburban and rural settings. Similarly, Table 3-8 and Table 3-9 summarize data from the EEI Study, comparing the range of costs per mile for OH transmission to UG transmission conversion, and for OH distribution to UG distribution conversion.

Table 3-6 Cost per Mile Comparison for New Transmission Construction

New Transmission	Urban	Suburban	Rural
OH Min Cost ($K/mi)	$377	$232	$174
OH Max Cost($K/mi)	$11,000	$4,500	$6,500
UG Min Cost($K/mi)	$3,500	$2,300	$1,400
UG Max Cost($K/mi)	$30,000	$30,000	$27,000
UG Min/OH Min Ratio	9.3	9.9	8.0
UG Max/OH Max Ratio	2.7	6.7	4.2

Table 3-7 Cost per Mile Comparison for New Distribution Construction

New Distribution	Urban	Suburban	Rural
OH Min Cost ($K/mi)	$127	$111	$87
OH Max Cost($K/mi)	$1,000	$908	$903
UG Min Cost($K/mi)	$1,141	$528	$297
UG Max Cost($K/mi)	$4,500	$2,300	$1,840
UG Min/OH Min Ratio	9.0	4.8	3.4
UG Max/OH Max Ratio	4.5	2.5	2.0

Table 3-8 Cost per Mile for Converting OH Transmission to UG Transmission

Convert Transmission	Urban	Suburban	Rural
Min Cost ($K/mi)	$537	$1,100	$1,100
Max Cost($K/mi)	$12,000	$11,000	$6,000

Table 3-9 Cost per Mile for Converting OH Distribution to UG Distribution

Convert Distribution	Urban	Suburban	Rural
Min Cost ($K/mi)	$1,000	$314	$158
Max Cost($K/mi)	$5,000	$2,420	$1,960

The data in Table 3-6 and Table 3-7 highlight the fact that new UG transmission construction is generally three (3) to ten (10) times more costly than new OH transmission construction, depending on the location. Similarly, new UG distribution construction is generally two (2) to nine (9) times more costly than new OH distribution construction, depending on the location. However, in both cases, it is less costly to underground lines in rural settings than urban settings (due mostly to the

[34] EEI, Out of Sight, Out of Mind 2012, An Updated Study on the Undergrounding Of Overhead Power Lines, Kenneth L. Hall, P.E., January 2013

complexities of urban UG construction: pricey real estate, congestion, need for manholes, conduits, vaults, etc.).

Table 3-8 and Table 3-9 show that for transmission conversion, the costs range from $537,000 per mile for urban construction (where there is existing UG infrastructure with duct space to pull new cable), to $12 million per mile for urban construction in cases where infrastructure, ducts, manholes, vaults, etc., have to be built. For distribution conversion, the costs range from $158,000 per mile for rural construction (using direct buried cable) to $5 million per mile for urban construction (where infrastructure, ducts, manholes, vaults, etc., need to be laid down).

Based on the new construction and conversion cost data, and evidence presented in other studies, the 2014 EEI Report (Before and After the Storm) concludes the following:[35]

> *"… the costs associated with converting overhead systems underground have made widespread use of such measures cost prohibitive. Of the studies EEI reviewed, there was not a single study that recommended a complete conversion of overhead distribution infrastructure to underground facilities. In fact, none of the studies could identify a single state requiring complete conversion of its distribution system as the costs, estimated to be in the billions of dollars, were not economically feasible and would severely impact customer rates."*

That being said, the EEI Report goes on to make a salient point regarding selective undergrounding:

> *"… undergrounding could be a viable solution to hardening the infrastructure through targeted or selective undergrounding rather than a total conversion. This might include placing the worst performing feeders, or feeder portions, underground or placing substation feeders that affected numerous customers underground. Targeted undergrounding was also recommended for those feeders supplying areas that were vital to the community such as police and fire departments, gas stations, hospitals, pharmacies and stores."*

The next section presents a recommendation to the BPU for undergrounding selected feeders or portions of feeders to improve blue-sky reliability and storm resiliency. The recommendation includes a methodology to select viable candidates for undergrounding.

3.2.3 Selective Undergrounding

It has been well documented (and discussed earlier in this report) that the recent snowstorm and hurricanes in NJ brought down numerous trees which accounted for a significant portion of T&D infrastructure damage, and contributed to prolonged restoration times. A natural reaction to this mode of damage is to look into the benefit of undergrounding the system. The previous sections highlight that while there are benefits (and also, drawbacks), burying all lines is cost prohibitive; but there may be tangible benefit to burying *selected* lines.

One of the benefits is certainly an improvement in reliability during normal (non-storm) days. Major causes of reliability problems for most utilities include severe weather, trees, and animals, particularly birds and squirrels. Figure 3-4 shows the major causes of interruptions from a survey of fifty-four (54) utilities.[36] The bars shaded in green represent the causes of outages that could be

[35] EEI, Before and After the Storm: A Compilation Recent Studies, Programs, and Policies Related To Storm Hardening and Resiliency, Updated March 2014

[36] From a survey of 54 U.S. utilities for DSTAR P14-9 Guide to Best Practices for Reliability Improvement, www.dstar.org

mitigated by burying the appropriate lines. This includes three of the top four causes: wildlife, vegetation, and severe weather/lighting. In many cases, improvement in reliability (due to reduction in tree contact for example) can be considered a proxy for improvement in storm resiliency.

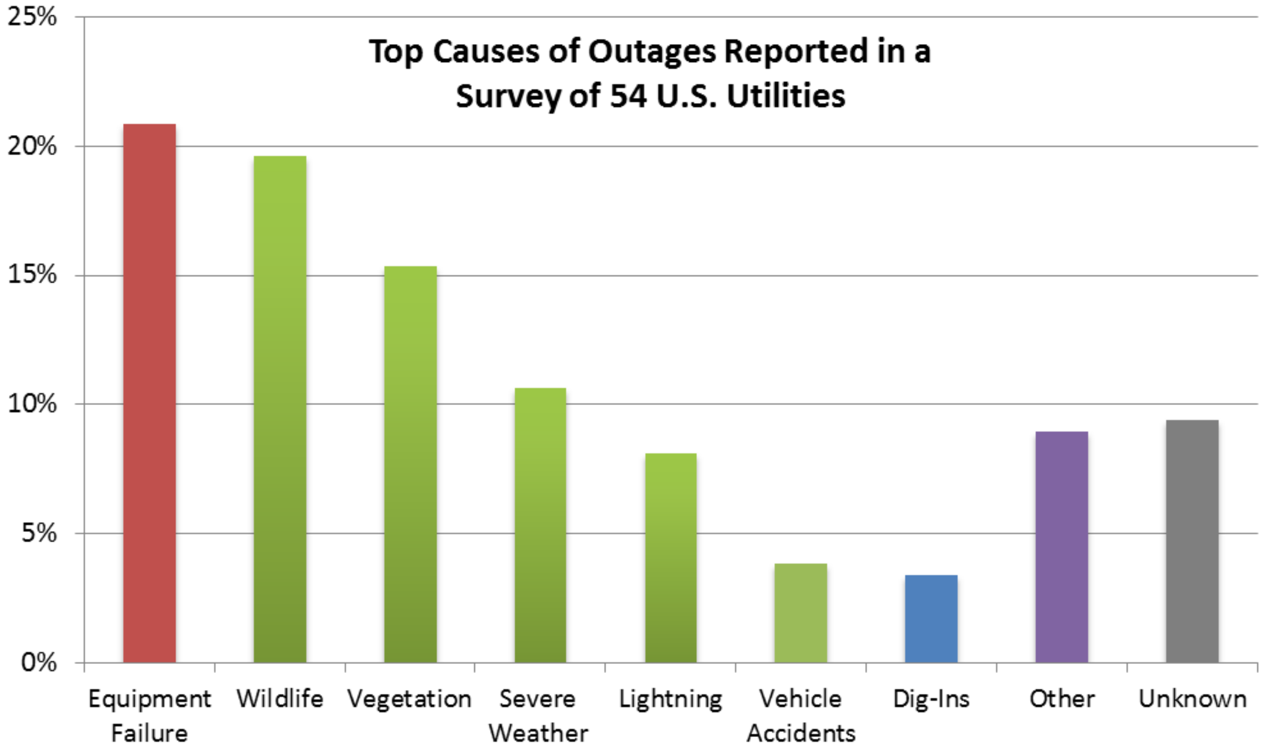

Figure 3-4 Major causes of interruptions from a survey of U.S. utilities

Across the country, many entities are seeing a clear link between undergrounding and storm benefit (not just blue-sky reliability) and are advocating or implementing undergrounding programs. These include plans and proposals developed by utilities as well as a number of initiatives at the commission, legislative, and executive levels to facilitate selective undergrounding. The next section discusses several of these examples, which lead up to a recommendation to the Board.

Undergrounding Case Study 1: Dominion Virginia Power

Dominion Virginia Power operates 6,400 miles of transmission lines and 57,000 miles of distribution lines in Central and Eastern Virginia and Eastern North Carolina. Several years ago they initiated a program to improve reliability and storm performance via selective undergrounding. About 60% of Dominion's distribution lines are overhead.

Based on history, the company knew that a majority of blue-sky reliability issues, and (more to the point) storm-related problems were on the overhead system. However, after some analysis they realized that "*50% of major storm damage was occurring on 20% of overhead tap lines.*"[37]

Therefore if they could improve the 20% worst performing tap lines, they could potentially cut restoration time in half after major events and prevent customers from becoming "frustrated and

[37] "Zero In 2014," Presentation to DSTAR Consortium at Spring 2014 Meeting by Dominion Power, Richmond, VA, April 2014

angry" with the restoration progress, as Figure 3-5 illustrates. Based on these findings, Dominion initiated a 12-year program to underground 350 miles of taps per year at an annual cost of approximately $175 million.

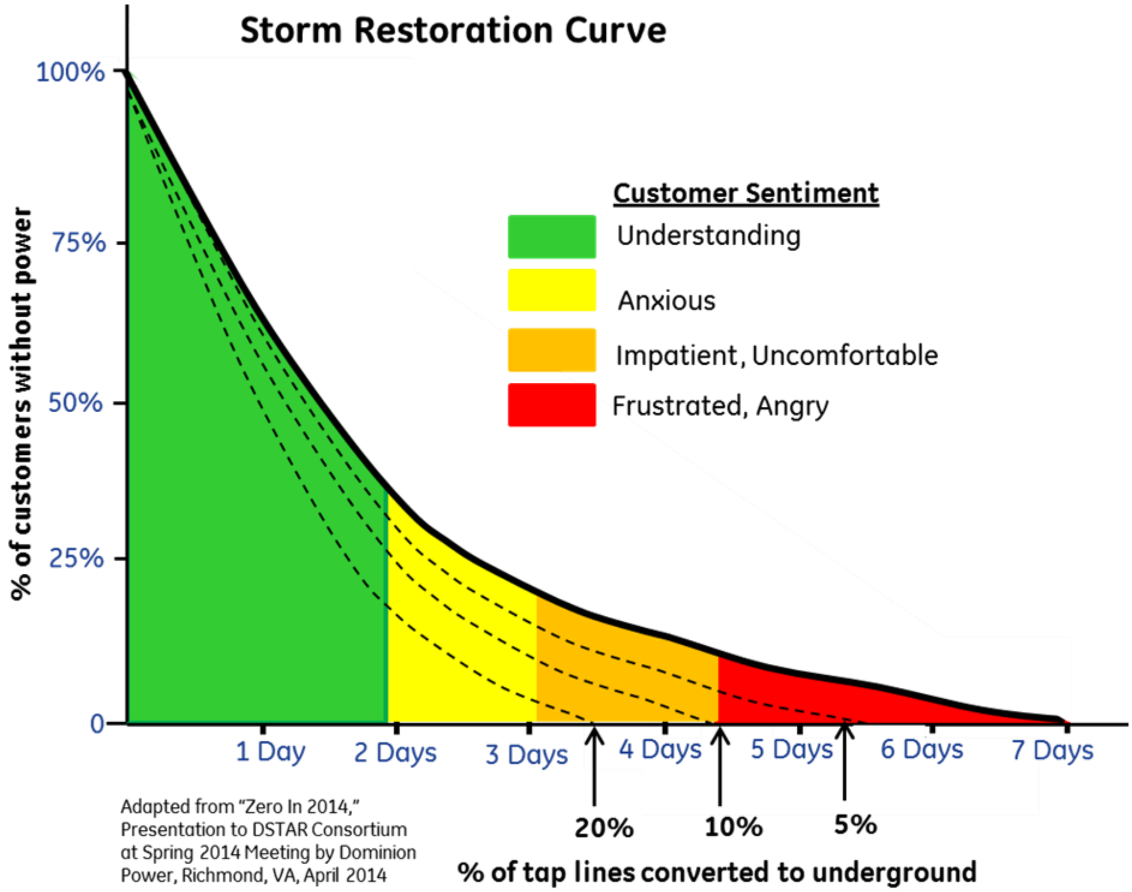

Figure 3-5 Dominion Restoration Curve shows Restoration Improvement from UG Tap Lines

Undergrounding Case Study 2: Pepco/DC

The District of Columbia recently passed the Electric Company Infrastructure Improvement Financing Act of 2014, known as the "Undergrounding Law" which:

> *"…established a process to select and finance the undergrounding of selective Pepco overhead power lines in order to increase electric distribution system reliability and to reduce the economic, social, and other impacts on the District's electricity users caused by repeated power outages."*[38]

The Pepco plan proposes to underground the main trunk and laterals of about 60 feeders (one-third of Pepco's OH feeders) over seven (7) to ten (10)years at a total cost of approximately $1 billion. The utility provided data and analysis to the DC Public Service Commission to justify how feeders were selected for undergrounding.

[38] Public Service Commission of the District of Columbia, Press Release, "Commission Receives Application for Approval of the Pepco/DDOT Power Lines Underground Projects Plan," Washington, DC, June 2014

This included a ranking of every overhead feeder by reliability, including the frequency and duration of outages and customer minutes of service interruption from 2010 to 2012, including storm outage data.

The DC PSC used the ranking data as well as data on other reliability enhancement work, safety factors, value of service factors, and the impact of construction within individual neighborhoods as criteria for selecting the projects for this plan.

Based on a study of 6 typical circuits by Shaw Consultants, the DC PSC projected that:[39]

- Replacement of overhead primary with underground primary will result in a decrease of 1.4 primary outage incidents per circuit-mile
- Duration (CAIDI) for non-storm incidents would increase approximately 1.6 hours, with an average UG primary restoration time in the range of 4.4 hours per outage incident

State Initiatives on Undergrounding

Several state activities related to undergrounding are listed in the EEI Report (Before and After the Storm). They include:

North Carolina	In a study conducted in conjunction with the investigation into the December 2002 ice storm, the PSC Staff recommended that companies identify overhead facilities that repeatedly experience reliability problems, determine whether conversion to underground is a cost-effective option and, if so, develop plan for undergrounding those facilities.
Maryland	The governor's grid resiliency task force issued no specific recommendations concerning undergrounding or other. The consensus among the roundtable participants was that undergrounding can significantly reduce outages caused by falling vegetation and high winds. However, due to costs considerations, selective undergrounding is preferable to complete undergrounding of the electric distribution system.
New Jersey	Undergrounding of distribution lines is governed under Section 14:3-8.4 of the New Jersey Administrative Code. Under the regulations, distribution lines are required to be constructed underground for new residential developments and streets that are constructed after August 2005 (several other states have similar provisions). Additionally, a NJ legislative proposal requires new electric distribution lines to be located underground "wherever practicable" and establishes the "New Jersey Task Force on Underground Utility Lines" in the Department of Community Affairs.

The preceding case studies and discussions lead to the following recommendation to the Board:

[39] Public Service Commission of the District of Columbia, Mayor's Power Line Undergrounding Task Force, August 23, 2012

Recommendation DH-6: Selectively underground most critical feeders and tap lines

***Selectively underground** the most critical distribution feeders and tap lines, **where practical**, to improve reliability and reduce major storm restoration time.*

The previous discussion highlights the fact that utilities, jurisdictions and states that have considered undergrounding, have selected circuits with attributes that make undergrounding technically feasible and economically justifiable. This recommendation provides the BPU with a methodology to select viable candidates for undergrounding.

The data needed to select and rank suitable candidates for undergrounding include the following:

- Location of circuit (e.g. coastal, mountain, urban, rural, suburban, etc.);
- Physical attributes of circuits (e.g. age, construction type, soil type, etc.);
- Number of customers, type and restoration priority (or criticality) by circuit;
- Historical reliability and storm performance of feeders (frequency and duration of outages, storm damage, restoration times, etc.);
- Probability of weather event impacting the circuit i.e. exposure or vulnerability to ice, wind, snowstorm, trees, etc.

With these data, the general methodology below can be used to select the most critical distribution feeders and tap lines for undergrounding:

1. Determine attributes that make circuits/segments/taps good candidates for undergrounding (consider performance of existing UG circuits). Examples of attributes include: reliability issues, storm damage, restoration time, number of customers, number of critical loads (hospitals, emergency services, etc.), age/eligibility for upgrade or replacement, ongoing excavation or construction in the vicinity.
2. Assign weights to the attributes to reflect their importance.
3. Score the circuits/segments/taps with regard to each attribute and determine the weighted multi-criteria rank for each circuit.
4. Select and evaluate the top ranked candidates for undergrounding.

The output of this process will be a list of critical circuit/segments/taps with attributes that make them attractive candidates for undergrounding, and a documented, defensible methodology for justifying the rankings.

3.3 Ground-based Inspection

Inspection and maintenance (I&M) of distribution assets is still the first line of defense against equipment failure and poor reliability. Proper inspection can identify problematic line components and add value to aging distribution systems by increasing asset utilization. Damaged poles and equipment are more likely to fail during storms, leading to more outages and delayed restoration. The graphic in Figure 3-6, based on data from Florida Power & Light's post Hurricane Wilma report, illustrates that “Presence of Deterioration” was a major cause of pole damage on laterals in FPL’s service area during Hurricane Wilma.[40]

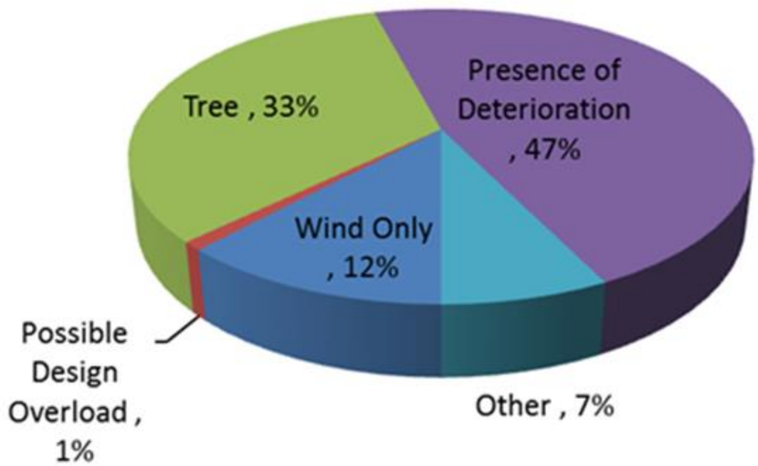

Figure 3-6 FPL pole failures on laterals by cause during Hurricane Wilma

Utilities typically set aside portion of their annual operating budget for inspection and maintenance programs, which vary by size of service area. The I&M budget is then allocated to different activities, roughly classified as overhead, underground and vegetation.

The allocation among the categories varies for each utility but the distribution of funds can give an idea of the critical issues in the service territory or the company’s priorities. Figure 3-7 from a survey of DSTAR Consortium utility members shows an estimate of the budget allocation for inspection for two utilities, one in the Southeast and the other in the Midwest.[41]

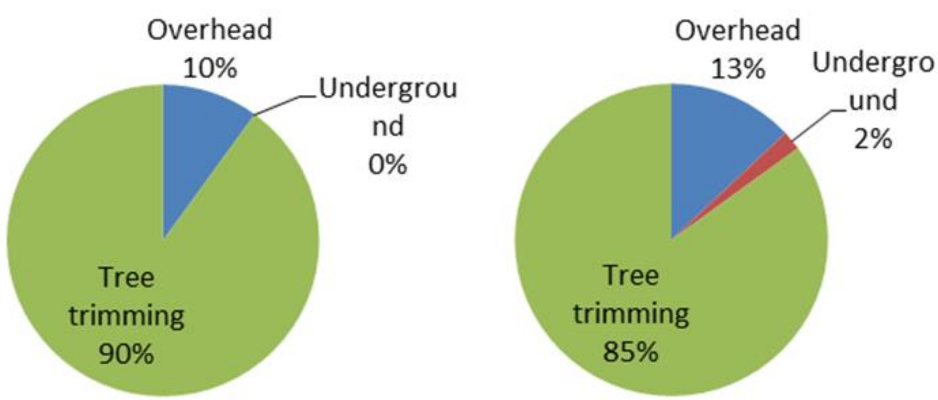

Figure 3-7 I&M budget allocations for a Southeastern and Midwestern IOU

In each case, the IOU spends at least 80% of its I&M budget on tree trimming/vegetation patrol and 10-15% on overhead line patrol.

[40] KEMA Inc., Technical Report: Post Hurricane Wilma Engineering Analysis, Prepared for FPL, January 2006

[41] DSTAR Project 13-3, “Survey of Inspection & Maintenance and Thermal Imaging Practices,” December 2013, www.dstar.org

3.3.1 Inspection Frequency

Most utilities inspect wood poles and associated equipment on a cyclic basis typically ranging from 8 to 15 years depending on their location. In the DSTAR Consortium survey mentioned earlier, the members reported that wood poles are inspected every 5 to 15 years and non-wood poles are not routinely inspected. Decay severity guides, such the RUS map in Figure 3-8, can be used to select an appropriate inspection cycle.[42]

- New Jersey, for example, is in Zone 4, which recommends initial inspection of wood poles in eight (8) to ten (10) years and subsequent re-inspection every 10 years.
- In Florida (which is in Zone 5), the PSC ordered utilities to implement an 8-year wood pole inspection cycle and report prior year results annually.

The Quanta report to the Texas PUC contains a survey of utilities in Texas. With regard to inspection cycles, the report states:

> *"Most utilities reported a ground-based inspection (GBI) program for both their transmission and distribution systems … cycles vary from annually to ten years for the transmission system and from annually to 15 years for the distribution system."*[43]

Figure 3-8 RUS Decay severity zones for wood poles (1= least severe, 5= most severe)

[42] United States Department Of Agriculture Rural Utilities Service, RUS Bulletin 1730B-121, Wood Pole Inspection and Maintenance, August 13, 2013

[43] Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs, PUCT Project No. 36375, Richard Brown, Quanta Technology, March 4, 2009, page 43

3.3.2 Inspection Methods

A line patrol can detect many problems such as damaged or compromised poles, stranded conductors, broken insulators, and loose hardware that could eventually lead to reliability issues and exacerbate storm damage. The patrol can be carried out in a vehicle, on foot or from the air. Vehicle patrol is commonly regarded as the most cost-effective way to conduct regular line inspections. Foot and aerial patrols are more suitable for areas with limited accessibility. Line patrols may be combined with specialized equipment such as infrared cameras, telescopic video cameras, and camera recording units to allow more detailed analysis, review, and documentation of problems.

Climbing and bucket inspections are sometimes the only way to identify or confirm problems on pole structures or on elevated levels in substations. The inspections can either be visual or with tools and equipment. Whereas climbing and bucket inspections are generally performed less frequently than foot patrol inspections, they provide a close-up view of elevated components and also permit minor repairs or adjustments to be made at the time of the inspection.

The most basic wood pole inspection procedure involves visual inspection of the pole and equipment for obvious defects, signs of wear, and safety issues, typically along with sounding (with a hammer) for integrity. More rigorous inspection methods include boring, partial excavation, acoustic techniques, moisture meters, shigometers, and x-ray tomography. Steel poles are susceptible to rust and corrosion and should to be inspected on a regular basis. Fiber composite poles are essentially maintenance free.

3.3.3 Targeted Inspection

The state of New Jersey is considering requiring annual inspections of overhead lines as a way to harden the infrastructure to reduce storm damage and speed up restoration. This one-year inspection cycle is more frequent than what is prescribed by the RUS decay severity map for NJ (8 to 10 years), and more than what several states (FL, MD, NY) use as a minimum standard. With that in mind, a key assumption is that <u>annual inspection is a visual examination</u> of pole structure and equipment condition without the use of invasive methods, advanced techniques or treatment.

In his review of wood pole inspection programs, Daugherty (1998)[44] presents data and references to show that visual inspection (even several times a year),

> *"… provides little information to help improve pole plant [and] misses most reject and priority poles." Daugherty (1998) goes on to make the point that, "18 to 24 in. excavation plus sound and bore every 6 to 10 years depending on severity zone, used with visual inspection, will find 98% of reject and priority poles."*

These excerpts highlight a key point: <u>the method of inspection is likely a greater determinant of success than the frequency of inspection</u>. In other words, how often the line is inspected may be less important than how the inspection is performed. Mandating more frequent inspections may be pointless unless the directive takes into account the critical balance between frequency and efficacy.

[44] Gerald L. Daugherty, The Realistic Expectation of an In-Place Wood Pole Inspection Program, 1998

Data and methods currently exist to develop appropriate inspection cycles and select techniques that are targeted toward priority feeders. NY and other states are ordering safety and reliability inspection of utility poles and targeted replacement or removal of deficient ones. These observations lead to the recommendation below.

Recommendation DH-7: Determine the most cost-effective inspection cycle/method

***Determine** the most **cost-effective inspection cycle and method** for poles and associated equipment by circuit, **and prioritize** based on criticality and condition.*

This recommendation will allow the EDCs to prioritize pole inspection based on criticality and condition, and permit more rigorous techniques to be applied to critical circuits than what may be feasible with annual cyclic inspection. This could lead to more effective use of the inspection and maintenance budget. The data needed to implement the process includes:

- Historical failures and associated customer interruptions linked to deteriorated poles or equipment
- Circuit-level reliability indices (SAIDI, SAIFI, CAIDI, MAIFI)
- Number of customers out, restoration times, number of poles and associated equipment damaged/replaced during past storms
- Inspection and maintenance records

With these data, the general methodology below can be used to determine the most cost-effective inspection cycle and method for poles and equipment by circuit:

1. Determine the statistical correlation between inspection cycle/method and circuit reliability (SAIDI, SAIFI, CAIDI);
2. Use the transfer function to adjust circuit failure rates by segment in a model in order to simulate changes in inspection practices;
3. Calculate a response surface to quantify the change in circuit reliability due to changes in inspection cycle and method;
4. Use the results to select the optimal level of inspection (cycle and method) to achieve a specified expected level of reliability ; and
5. Use expected level of reliability as a sensitivity variable and quantify incremental change in inspection costs.

The key outputs of such an analytic process include:

- Optimal inspection cycle and method for each circuit to maximize reliability for a given budget
- Optimal inspection cycle and method for each circuit to minimize cost for a given reliability target

3.3.4 Cost of Annual Ground-Based Inspection

The reports submitted by the BPU to GE as part of this study did not contain any data on the cost incurred by the EDCs for ground-based inspection. However, the Quanta Report to the Texas PUC[45] contains survey data that can be used as a proxy.

In the Quanta Report, the wide variation in ground-based inspection cost per mile for both transmission and distribution was attributed to the types of structures involved, the number of structures per mile, whether climbing was performed, and what technology and procedures were used. For example, Entergy Texas reported a high ground-based inspection cost, over $230 per mile, because it included the cost of sounding and boring to check for wood deterioration.

The Quanta Report assumed that the average cost for ground-based inspection for transmission facilities in Texas was $500 per mile, and that the average cost for distribution ground-based inspection (including repairs) was $200 per mile. Based on these data points, the annual costs for ground-based inspection for transmission and distribution in New Jersey were projected to be $800 per mile and $320 per mile respectively.[46] The GBI inspection cost for subtransmission, determined by linear interpolation between distribution and transmission costs, is $560 per mile.

Therefore, given the miles of transmission, subtransmission, and distribution circuits reported by the EDCs in the EPP Report and other public sources, the cost for annual vegetation inspection for the EDCs is shown in Table 3-10 below.

Table 3-10 Cost of Annual Ground-Based Inspections for NJ EDCs

	ACE	JCP&L	PSE&G	RECO
Transmission Miles	1,121	2,550	1,500	35
Subtransmission Miles	240	1,812	2,393	-
Distribution Miles	10,352	22,670	19,620	853
Annual GB Inspection Cost ($1000)	**$4,344**	**$10,309**	**$8,818**	**$301**

The total cost for annual ground-based inspections for the New Jersey EDCs is approximately $23.8 million. This is about 26% of the estimated 2014 total VM budget for all four EDCs (~$90 million, based on data in the EPP Report).[47] DSTAR utilites reported in a survey that their combined overhead inspection budget was between 10% and 15% of their total vegetation management budgets. While the proportion for New Jersey EDCs is higher than the survey findings, it is based on proxy data from another state, and should not be used to draw definitive conclusions.

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45 Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs, PUCT Project No. 36375, Richard Brown, Quanta Technology, March 4, 2009.

46 GBI Inspection cost per mile data from Quanta report, adjusted for inflation using an average inflation rate of 2.2% to covert 2009 dollars to 2014 dollars; Average cost of living adjustment of 1.4 was applied to adjust TX costs to NJ costs; (See http://www.bls.gov/data/inflation_calculator.htm and http://money.cnn.com/calculator/pf/cost-of-living/).

47 The table on Page 120 of "Performance Review of EDCs in 2011 Major Storms," Prepared by Emergency Preparedness Partnerships lists a total annual VM budget of ~$75 million in 2011. Costs were escalated at 7% per year to $90 million for 2014.

3.4 Pole and Hardware Upgrades

Severe weather can cause damage to distribution poles and structures in many ways, for instance:

- Extreme winds can bring down entire trees into the power lines, snapping the conductor or causing damage to cross arms, insulators or even breaking the pole.
- Flying debris such as tree branches or other materials can also cause damage to overhead structures.
- Loading conditions created by extreme winds or severe storms often exceed the design specification of overhead construction resulting in damaged or broken structures. Most utilities use wood poles in overhead construction due to the fact that they are widely available, maintainable, relatively inexpensive, and can last well over 30 years with proper treatment.

However, the most common class of distribution wood pole construction, Grade C, is more likely to failure under extreme wind loading conditions compared to higher grade alternatives (Grade B), and compared to some non-wood, engineered alternatives. The history of wood pole failures during storms has prompted utilities in storm-prone states such as Texas, Florida, and New Hampshire to consider the use of higher grade construction and alternative materials for reliability and resiliency purposes.

3.4.1 NESC Loading Zones

The National Electric Safety Code (NESC), also referred as IEEE/ANSI Standard C2-2012[48] is a set of guidelines for protecting employees and the public from safety hazards that might arise during installation, operation, or maintenance of electricity supply and communication systems. The NESC defines three grades of construction, Grade B, Grade C and Grade N. Grade B construction (the highest) is generally recommended for transmission, and Grade C is used for mostly for distribution.

Ice and wind loading requirements for both Grade B and C have been developed for three loading districts or zones; Light Loading Zone, Medium Loading Zone, and Heavy Loading Zone. Figure 3-9 shows the NESC combined ice and wind loading map for the US, (Rule 250B in the code).

The (average) loads defined in NESC Rule 250B for the three loading zones are:

- Heavy: ½ inch radial thickness ice, and 4 lb/ft^2 of wind (equivalent to a 40 mph wind);
- Medium: ¼ inch radial thickness ice, and 4 lb/ft^2 of wind (equivalent to a 40 mph wind);
- Light: 0.0 in. radial thickness ice, and 9 lb/ft^2 of wind (equivalent to a 60 mph wind).

In the Heavy Loading Zone which includes the state of New Jersey (outlined in red on Figure 3-9), Grade C construction is recommended for distribution structures (below 60 feet) and Grade B construction, which is generally 50% stronger than Grade C construction, is recommended for transmission structures (over 60 feet).

[48] 2012 National Electrical Safety Code (NESC), C2-2012, vol., no., pp.1-354, August 1, 2011

As can be seen on the loading map, the NESC loading zones are quite broad and therefore the requirements apply to *average* conditions over a large part of the country. For example, using the Rule 250B map, a designer might assume that the applicable ice and wind loading for New Jersey, (½inches of ice and four (4) lb/ft^2 of wind), is the same as that for north Texas, since they are both in the Heavy Loading Zone. However, the reality is that even the *average* icing and wind conditions in parts of New Jersey are more severe than they are in north Texas.

Not surprisingly, in some areas of the country, the loading described by the NESC Rule 250B can be quite different from the maximum loading dictated by local conditions. Because the NESC Rule 250B is predicated on averages across wide areas of the country, it informs about "*conditions that can be expected to occur frequently, rather than providing information about the maximum wind or ice that may be expected with a 50 year or 100 year recurrence*."[49] Consequently, the NESC should be considered the minimum mandatory requirement for loading and design, and states and utilities should adapt their design standards to promote resiliency during more extreme events.

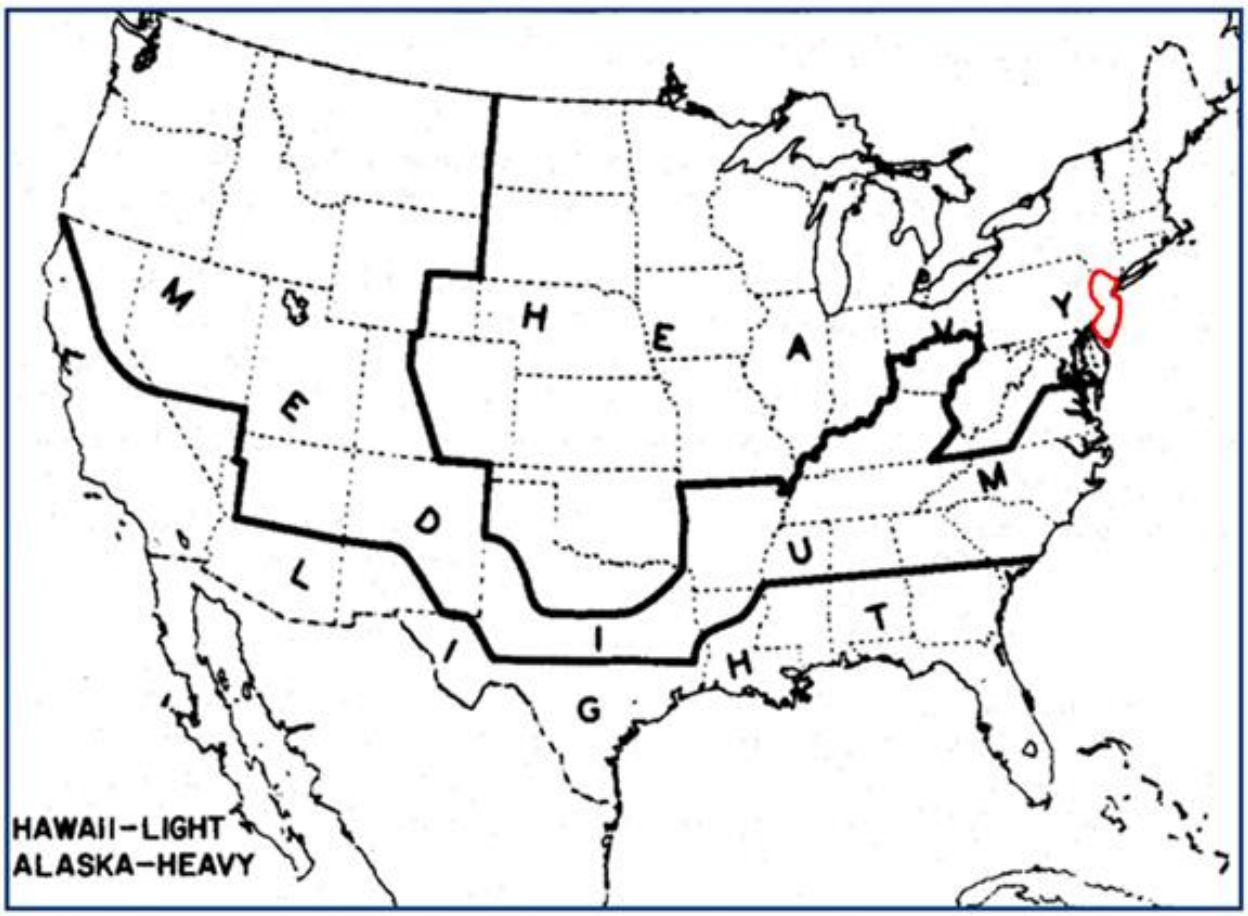

Figure 3-9 NESC combined ice and wind loading map for the U.S. (Rule 250B)

[49] NEI Electric Power Engineering, New Hampshire December 2008 Ice Storm Ice Storm Assessment Report, Appendix F - Overhead Line Construction, October 2009

There are other construction standards in use across the country with more conservative requirements than the NESC. One of these, ASCE Standard 7-05[50] divides the country into much smaller areas than are shown in the NESC district loading maps, and presents information on wind speeds and ice loads with more granularity than the NESC loading map. This standard is the basis for NESC extreme wind loading and extreme ice with concurrent wind criteria included in the 2007 revision of the code (discussed below). However, the NESC currently only requires that they be applied to structures over 60 ft.

3.4.2 NESC Extreme Ice and Wind Loading

For overhead line structures over 60 feet, (primarily transmission), NESC Rules 250C and 250D require that extreme wind loading criteria and extreme ice with concurrent wind loading criteria be applied to line design. Figure 3-10 shows the NESC extreme wind loading map for the mid and north Atlantic hurricane coastline (which includes New Jersey, highlighted in red).

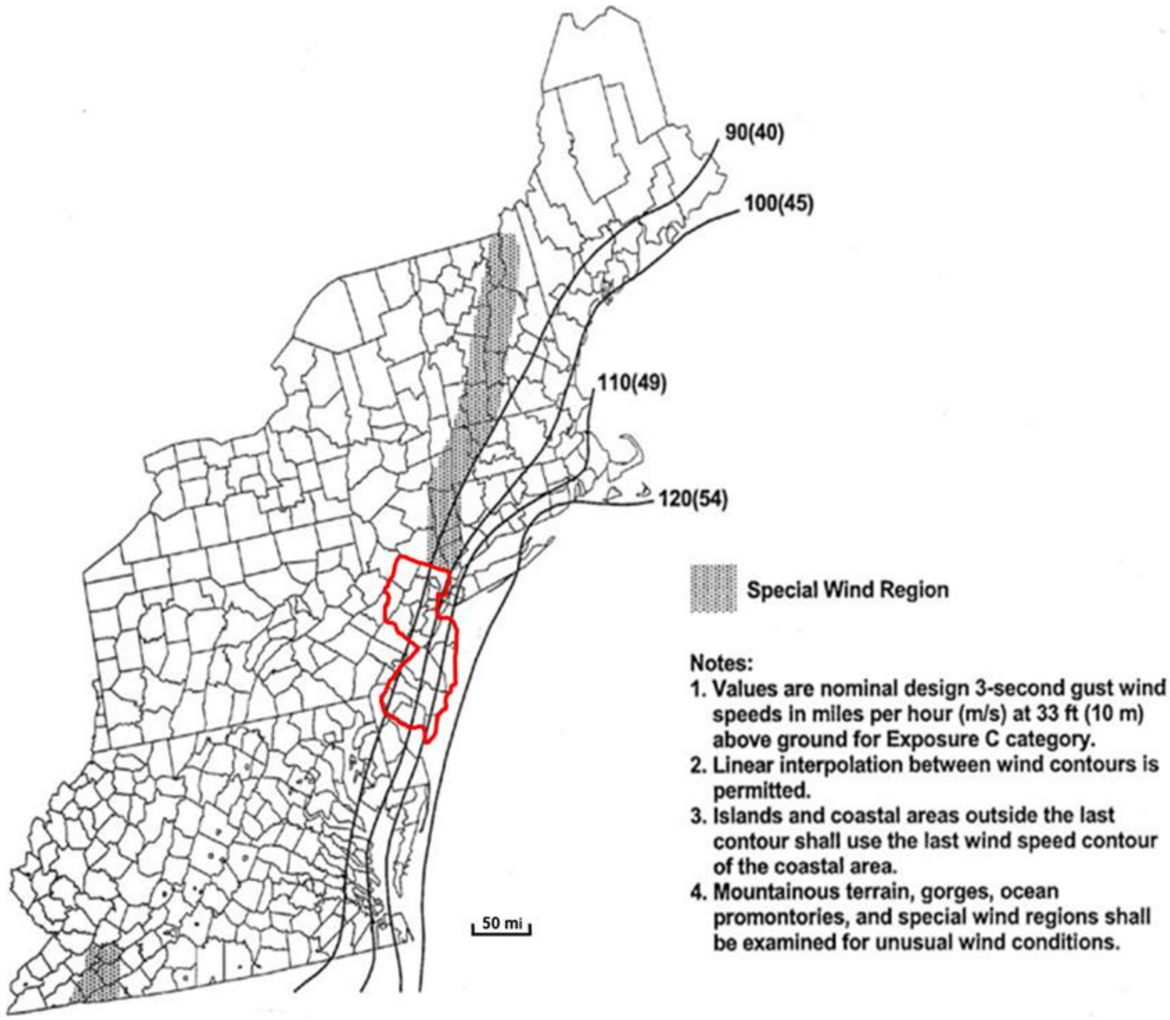

Figure 3-10 NESC extreme wind loading map: mid and north Atlantic coastline (Rule 250C)

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[50] American Society of Civil Engineers, ASCE Standard 7-05, "Minimum Design Loads for Buildings and Other Structures," 2005

The contour lines on the extreme wind map show that:

- Within 10 to 15 miles of the coast, three (3)second wind gusts between 110 and 120 mph can occur at a height of 33 feet above ground;
- Between roughly 15 and 25 miles of the cost, 3-second wind gusts between 100 and 110 mph can occur at a height of 33 feet above ground; and

Between roughly 25 to 50 miles of the cost, 3-second wind gusts between 90 and 100 mph can occur at a height of 33 feet above ground. According to the extreme wind map, the 50 year return wind gusts for New Jersey (90 to 120 mph) are far beyond the average wind loading in the NESC heavy district from Rule 250B, (equivalent of 40 mph) for which Grade C construction is recommended for distribution.

However, if extreme wind loading criteria were applied to distribution design (below 60 feet), it would result in Grade B construction, which is 50% stronger.

Some utilities in states that have similar exposure to extreme wind loading as NJ have chosen to use higher design standards than NESC Rule 250B for distribution. FPL, for example, has been building all distribution poles to Grade B construction. According to a 2006 Engineering Analysis Report by KEMA, "*FPL chose these design guidelines since it did not feel that the loading criteria in the NESC relevant to Florida (light combined ice and wind loading) adequately considered exposure to high winds during tropical storms and hurricanes*."[51]

The third loading condition in the NESC 2007 revision is extreme ice with concurrent wind. Figure 3-11 shows the NESC extreme ice with concurrent wind loading map for the eastern United States. The map's contours give the uniform radial ice thicknesses due to freezing rain, with concurrent 3-second gust speeds, for a 50-year return. For New Jersey (outlined in red), the following ice and wind loading combinations are applicable: ¾ inch ice with 40 mph wind in the northern tip and southern region; one (1) inch ice with 40 mph wind in a northwest pocket; and ¾ inch ice with 50 mph wind in the northeast. The 50-year return ice and wind loading for New Jersey is greater than that obtained from the Rule 250B map in Figure 3-9 (½ inch ice with 40 mph wind).

For New Jersey, the Rule 250C extreme wind loading and the Rule 250D extreme ice with concurrent wind loading are both greater than the Rule 250B combined ice and wind loading currently used to justify Grade C construction for most distribution lines.

Following an analysis of overhead line construction in New Hampshire after the 2008 ice storm, an NEI report made the following observation regarding overhead line designs based on NESC district loading (Rule 250B):[52]

> "*For some areas with higher than average icing loads or higher than average wind loads, both of which would be true of New Hampshire, these levels of loading have produced designs with higher than average failure rates. In areas of lower than average wind and ice loads these levels of loading have produced a more robust than necessary design*."

The NEI Report went on to make the following recommendation to the state:

[51] KEMA Inc., Technical Report: Post Hurricane Wilma Engineering Analysis, Prepared for FPL, January 2006

[52] NEI Electric Power Engineering, New Hampshire December 2008 Ice Storm Ice Storm Assessment Report, Appendix F - Overhead Line Construction, October 2009, Page F-9, Page F-14

"It is recommended that all structures, <u>regardless of height</u>, be designed for not only district loading but also extreme wind and extreme ice with concurrent wind as is now required in the NESC for structures exceeding 60 ft. in height. This should prevent widespread damage to the distribution system during a weather event with a 50 year return period which the distribution system would be expected to experience at least once during its design lifetime."

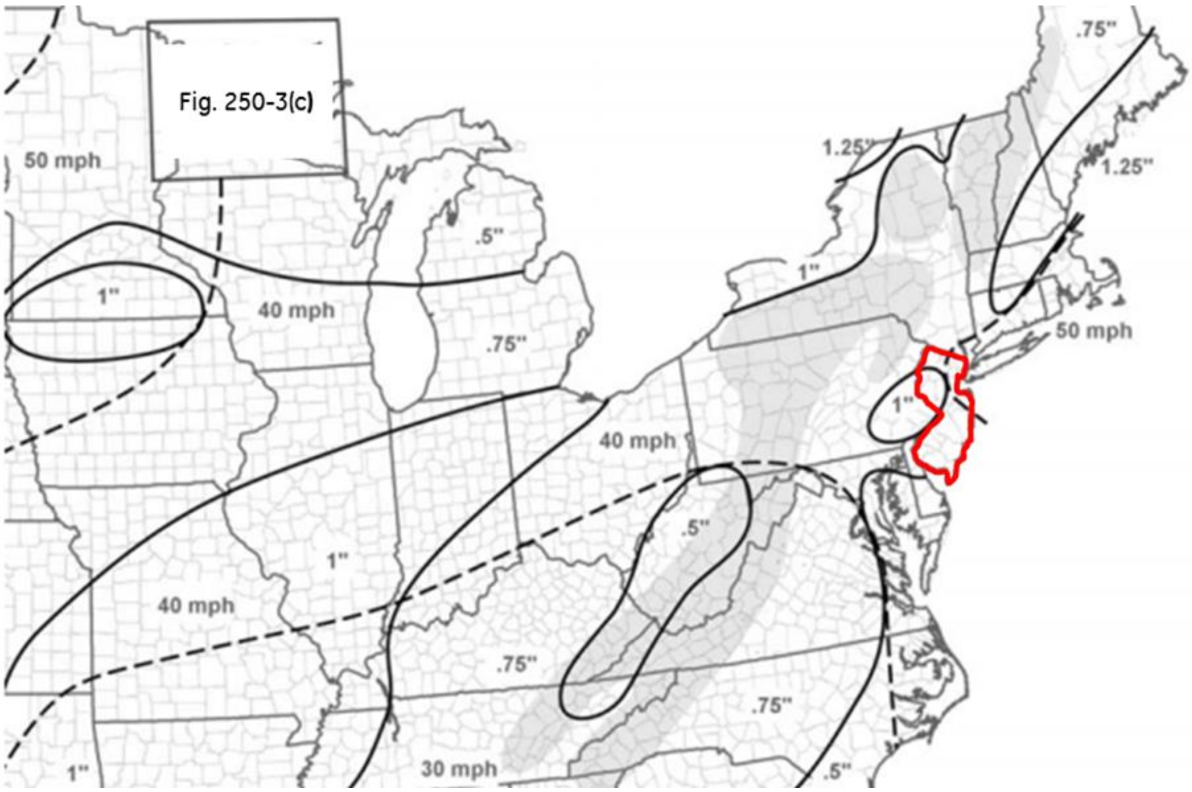

Figure 3-11 NESC extreme ice w/ concurrent wind loading map for Eastern U.S. (Rule 250D)

3.4.3 Targeted Upgrades

After the 2005 hurricanes, the Florida PSC considered requiring that all distribution lines be designed to the NESC extreme wind loading criteria (as FPL had been doing for years prior to the storms). The utilities in Florida indicated that this requirement would result in cost increase of 2 to 4 times over the base design cost. Consequently, the PSC required utilities to harden lines serving critical infrastructure and to complete forensic analysis in future storms to evaluate the effectiveness of the targeted hardening, which included more robust overhead line design in some areas.

The EEI Report, "Before and After the Storm," lists and summarizes a number of industry studies that reference higher design and construction standards for overhead lines. The bottom line of the review was that:[53]

[53] EEI, "Before and After the Storm – Update: A Compilation of Recent Studies, Programs, and Policies Related to Storm Hardening and Resiliency," March 2014, Page 7

"The studies generally recommended, as with undergrounding, that widespread system hardening is cost-prohibitive and that the most effective use of hardening tools is through a targeted approach. The recommendations are to identify the most critical elements, the worst performing components, those units that have aged and weakened or those elements most in danger of failure and work to replace them with improved system designs such as composites, guying, stronger pole classes or relocation to name a few."

Based these discussions, and experiences in Florida and New Hampshire, the following recommendation can be made to the Board.

Recommendation DH-8: Upgrade construction near coast; design for extreme loading

Upgrade T&D construction near coastal areas to NESC Grade B, and incorporate extreme wind and ice loading criteria in all T&D design, regardless of height.

In New Jersey, the areas within 10 to 15 miles of the coast are particularly exposed to extreme winds with a mean 50-year recurrence (see Figure 3-10) and extreme ice and concurrent wind with a mean 50-year recurrence (see Figure 3-11). Undergrounding circuits near the coast may be problematic due to high likelihood of storm surge and flooding. Upgrading circuits "near" the coast to Grade B construction (which is 50% stronger than Grade C used for most distribution lines) will lead to more resilient structures.

The widespread use of Grade C construction for distribution is based on NESC Rule 250B district loading maps. The rule uses average ice and wind loading over large parts of the country and "*does not sufficiently incorporate local factors*."[54] ASCE extreme wind and ice loading criteria, which are the basis for NESC Rule 250C and 250D, lead to more resilient designs, but the current NESC revision only requires them for structures over 60 feet. Other line design codes, such as RUS guidelines "*suggest including these two loading cases in all designs*."[55] Targeted upgrade of distribution circuits near the coast to Grade B construction and incorporating extreme wind and ice loading criteria in T&D designs not just lines over 60 feet, will lead to more storm-resilient structures. This recommendation provides a method to determine which facilities should be upgraded. The data needed to select and rank suitable candidates for upgrade include the following:

- Number of distribution and transmission circuit structures, total length (miles), number of poles, towers and other structures within a set distance of the coastline;
- Historical damage records for coastal areas;
- Exposure/vulnerability of circuits to storm damage;
- Construction grade of feeder and structures.

With these data, the general methodology below can be used to select the most critical distribution feeders and tap lines for upgrade:

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54 NEI Electric Power Engineering, New Hampshire December 2008 Ice Storm Ice Storm Assessment Report, Appendix F - Overhead Line Construction, October 2009, Page F-9, Page F-14

55 U.S. Department of Agriculture, Rural Electrification Administration, *Mechanical Design Manual for Overhead Distribution Lines*, REA Bulletin 160-2, 1982

1. Analyze historical weather data to determine impact of flooding/storm surge on circuits at various distances from coast.
2. Assess the damage to overhead T&D structure due to wind, trees, ice, snow, etc. at various distances from coast.
3. Consider circuit historical reliability, storm performance, and criticality in terms of the number of customers and their restoration priority.
4. Determine the optimal distance from coast where upgrades are practical, impactful, and economic, and prioritize overhead circuits for upgrade to a design that incorporates extreme ice and wind loading criteria.

The output of this process will be a list of critical circuits with attributes that make them attractive candidates for upgrading, and a documented, defensible methodology for justifying the rankings.

3.4.4 Alternate Pole Material

No material is perfect when it comes to application to distribution systems. Wood and other non-wood alternative materials have advantages and disadvantages making the overall design choice a combination of both engineering and economic factors for each site. This section gives some insight into the benefits and drawbacks of different types of non-wood poles (relative to wood in most cases).

Electrical Property

Wood is naturally a non-conductor of electricity and thus acts as an additional layer of insulation. Similarly, fiber composite materials are also excellent insulators. On the other hand, steel and steel-reinforced concrete poles are highly conductive and need to rely on the pole or equipment insulators. The electrical strength of utility poles is commonly measured in terms of the critical flashover (CFO) voltage. Calculation of CFO strength is done using method defined by IEEE standard 1410.[56] The calculation and analysis of the CFO for standard pole configurations used by distribution utilities shows that steel and steel-reinforced concrete poles have a negative impact on CFO, while composite materials enhance or at least maintain the CFO level when compared to the equivalent wood configuration.

Mechanical Strength

Figure 3-12 shows typical loads and forces on a pole structure. The key measures of mechanical strength are listed below, and compared in Table 3-11:

- Strength-to-weight ratio: Material's strength (force per unit area at failure) divided by its density;
- Tensile and compressive strength: Material's ability to withstand bending force, tension (resistance to the stretching) and compression (resistance to the pressing);
- Elasticity: Material's ability to return to original shape after stress has been removed;
- Ductility: Material's ability to deform plastically without fracture or failing.

[56] IEEE Standard 1410TM-2004, IEEE Guide for Improving the Lightning Performance of Electric Power Overhead Distribution Lines, New York, NY, 2004. Page 12. [Finally, a page number.]

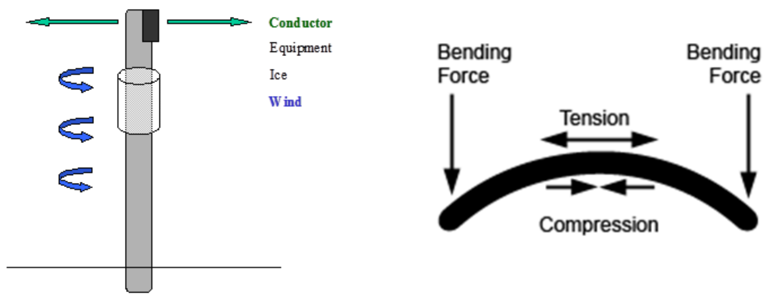

Figure 3-12 Typical loads and forces on a pole structure

Table 3-11 Comparison of physical properties of pole materials

Property	Wood	Concrete	Steel	Composite
Strength-to-weight ratio	Medium	Low	High	High
Tensile strength	Medium	Low	Extremely high	Extremely high
Compressive strength	Medium	High	Extremely high	Low
Elasticity	Medium	Low	High	Extremely high
Ductility	Medium	Low	High	Medium

Material Workability

During installation and repair of overhead distribution system, utility workers must be able to transport and erect pole structures efficiently and effectively. Poles can be direct-buried or mounted on grounding structures, and a variety of pole-top equipment and hardware need to be installed. The ease of workability of each pole material, particularly with regard to transportation, installation, climbability, field drillability, and disposal, directly impact the economics of selection.

- Composite poles are lightweight and easiest in terms of transportation followed by steel and wooden poles. Concrete poles are very heavy and most difficult for transportation.
- Wood and composite poles can be easily drilled in the field though caution is needed to avoid any health issues that may be caused by fiberglass dust. On the other hand, concrete and steel poles are usually predrilled by the manufacturer according to specifications. In circumstances where they need to be drilled in the field, special equipment is required, which increases installation cost.
- Utility workers have extensive experience climbing wood poles although there are some concerns regarding the preservative used to treat wood poles. Steel and composite poles require step attachments for climbing. Concrete poles can be climbed using ladders or step bolts.
- The chemical used to treat wood poles makes it hazardous and difficult to dispose whereas other non-wood poles do not contain toxic chemicals and are safe to store as landfill. Steel poles are recyclable.

Life Cycle factors

Various other environmental factors affect the performance and thus selection of material for pole structures. Aging due to environmental factors determine the life cycle cost of the pole. Wood poles are subject to rot, fungus and decay, pests and woodpeckers. Non-wood poles do not suffer from these factors, but they have their own disadvantages. Steel poles rust and corrode due to moisture and oxidation although zinc coating helps reduce the rate. Overtime, concrete may develop a patina wrinkles, craze cracks due to environmental effect. If moisture reaches inner steel reinforcement the rust developed might cause the concrete cover to split. Composite poles are very susceptible to ultraviolet rays and its surface deteriorates overtime. Thirty years is considered as a normal life span of wood poles whereas other non-wood poles go beyond 70-80 years.

System Reliability Impacts

The impact of wood and non-wood materials on system reliability can be viewed from contribution to both magnitude/duration of outages and the frequency. Outage duration is primarily affected by ease of transportation and installation, degree of climbability, and options for drilling. For example, in situations where a line needs to be repaired or pole-top equipment replaced, the mean time to repair (MTTR) could conceivably be less if the pole is wood or composite versus steel or concrete. But in situations where a pole needs to be replaced, and there are transportability or physical access issues, poles made from hollow steel or composite would be easier to transport and install compared to their heavier wood or concrete counterparts. Similarly, steel and concrete poles are pre-drilled by manufacturers and saves time; but wooden poles provide flexibility of drilling on-site.

Non-wood structures specifically steel and concrete have lower CFO level than wood or composite materials. These materials are more susceptible to flashover from lightning strikes potentially increasing the frequency of outages. Steel and concrete structures have an advantage over wood or composite in that they are less likely to fail in a vehicular collision. Steel poles are harder for animals such as squirrels, raccoons, and opossums to climb and can minimize animal-caused outages in certain areas. Also, in many cases steel poles tend to deform rather than fail completely during storms or after vehicular collisions. This gives time to replace and repair the pole without service interruption.

Recommendation DH-9: Insert steel/concrete structures in long straight wood circuits

Insert steel or concrete structures in long straight circuits with wood structures to prevent cascading failures (domino effect); alternatively reinforce wood poles with steel bands.

Structural damage constitutes a majority of damage to transmission and distribution lines during extreme wind, hurricane or extreme ice buildup. Failure of structures causes additional stress on neighboring structures. The stress can build up and propagate to neighboring structures causing a cascading failure. This is a typical phenomenon responsible for failure of wood pole construction, especially long straight lines in open areas.

A more resilient stronger structure is required to break the domino effect and halt cascading failures. Steel, concrete and composite structures provide this strength and can help reduce the damage to T&D lines. Alternatively, steel bands may be added to existing wooden poles for reinforcement.

The data needed to select and rank suitable candidates for upgrade include the following:

- Circuit location and construction information;
- Historical storm damage and failure modes for circuits.

Possible Implementation Steps:

1. Analyze historical records for instances of cascading failures;
2. Inspect and assess transmission/distribution for possible vulnerability to cascading failures;
3. Determine structures to be replaced to prevent cascading failures.

4 SUBSTATION HARDENING STRATEGIES

The task description from the BPU that relates to this chapter is given below. [1]

> *"Evaluate the costs and benefits of implementing the following requirements:*
>
> *a.) construction of new and/or relocation of existing electric substations above the 100-year floodplain*
>
> *b.) providing adequate back-up power for central offices and substations"*

This chapter summarizes the findings related to the efficacy of substation hardening, particularly flood avoidance and flood control strategies, and discusses the merits of backup power at substations and electric utility communication facilities. The term "communication facilities" has been substituted for "central offices" in the scope because telecom utilities were not in the scope of this study. All data and information from the BPU related to EDCs (Electric Distribution Companies), therefore item (b) of the original scope has been generalized to a discussion of the role of electric utility communication facilities during storms. The discussions lead to several key recommendations to improve the resiliency of EDC substations and communications facilities in New Jersey.

4.1 Construction of New and/or Relocation of Existing Substations

This subsection deals specifically with prevention of flood damage at electrical substations, which was an issue for several NJ EDCs during recent major storms. The EPP Report to the BPU, "Performance Review of EDCs in 2011 Major Storms," states:[2]

> *"Substation flooding had a substantial impact to the service and operations during the Irene hurricane event. Water intrusion impacted a total of 15 substations in New Jersey and flooding caused damage to relays, breakers, controls, bushings and bus work."*

The report further points out that of all EDC substations in the 100-year flood zone: none of ACE's twelve substations was affected; all seven of JCP&Ls were impacted; eight of PSE&G's twelve stations were damaged; and RECO's single station in the 100-year flood zone was not affected. During Hurricane Sandy, PSE&G reported that twenty switching stations and substations were affected by the storm surge and only one of these (the Marshall Street Substation in Hoboken) had previously been affected by flooding during Irene.[3] None of the other EDCs reported substation flood damage in their major event reports.[4]

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1 New Jersey Board of Public Utilities Consultant Tasking Document, *Electric Distribution Infrastructure Storm Hardening*, Dated January 10, 2013, Submitted to GE on February 13, 2014.

2 EPP Final Report, "Performance Review of EDCs In 2011 Major Storms," August 9, 2012, Page 109.

3 PSE&G's Final Report To The BPU Major Event Superstorm Sandy / Nor'easter October 27 - November 15, 2012, February 14, 2013.

4 GE has no knowledge of whether flooding occurred at other EDC substations and it was not reported in the MERs, or whether mitigation measures were successful. This is an example of the inconsistency in the MERs, which is discussed in Section 2.1.2.

GE determined that a number of electrical utilities outside of New Jersey experience extreme weather conditions similar to conditions experienced in New Jersey. GE attempted to contact representatives of several of these utilities in order to discuss strategies for damage prevention. In all, GE was able to speak to representatives or former employees from the following utilities:[5]

- Baltimore Gas and Electric (BGE)[6];
- City of Naperville Municipal Utility;
- Consolidated Edison Company of New York (Con Edison)[7];
- Public Service of New Hampshire (PSNH)[8].

GE reviewed reports and papers relating to electrical utility storm response and damage prevention. The following publications were reviewed.

- "Storm & Flood Hardening of Electrical Substations"[9]
- "PURA Investigation of Public Service Companies' Response to 2011 Storms"[10]
- EPP Final Report "Performance Review of EDCs in 2011 Major Storms"
- Various EDC Major Event Reports for Recent Storms, submitted by the BPU

GE also utilized the experience of its Energy Management substations projects team for additional information on flood damage prevention.[11]

Based on experience with substation design and construction, GE determined that relocating or constructing new substations is much more costly than implementing smaller scale strategies for individual or groups of equipment. For example, GE recently estimated the total design and installation cost for a new transmission and distribution substation at between $20MM and $40MM (the exact pricing and substation details cannot be disclosed because the information is proprietary). This does not include purchasing property for the substation relocation, cost of easements for distribution and transmission lines, design and construction of transmission line extensions, cost of reconfiguring distribution lines, limits on reuse of existing equipment (existing equipment has to remain in service until new station is energized), storage or disposal cost for existing equipment, and depressed land value at existing station due to past use.

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5 In addition to the listed utilities, GE contacted Florida Power and Light (FPL), Pepco and NSTAR Electric. FPL was not willing to participate in discussions. At the time of this report, Pepco and NSTAR had agreed to speak with GE; however, the representatives' schedules would not allow for interviews in time to include the information from the interviews in this report.

6 Santiago, Jose M, Constellation Energy (BGE), Telephone Interview, Oakbrook Terrace, IL, April 22, 2014.

7 Murphy, Patrick, Consolidated Edison (Con Edison), Telephone Interview, Oakbrook Terrace, IL, April 22, 2014

8 Christensen, Charles, Public Service of New Hampshire (PSNH), Telephone Interview, Oakbrook Terrace, IL, April 23, 2014.

9 Boggess, John M., et al. "Storm & Flood Hardening of Electrical Substations." IEEE 2014.

10 Betkoski, J. W., and House A. H., "Docket No. 11-09-09 PURA Investigation of Public Service Companies' Response to 2011 Storms." State of CT Dept. of Energy and Environmental Protection, Public Utilities Regulatory Authority, August 1, 2012.

11 Gacek, Dan, General Electric Energy Management (GE EM), Personal Interview, Oakbrook Terrace, IL, April 30, 2014.

Our experience with several electric utilities indicates that substations are only relocated to new sites due to extreme circumstances, such as failure of all substation yard foundations. Additionally, through the interviews listed above, GE found that other utilities faced with similar storms are using smaller scale strategies. Therefore, GE shifted the focus of this section of the report to discussion of implementation of smaller scale strategies.

4.1.1 Flood Control and Avoidance

Elevated water levels can result from various events, such as tsunamis, storm surge, flash flooding, or inundated rivers or lakes. These events are differentiated by the rate of change in the water level and the duration of the elevated water level.

While strategies for dealing with elevated water levels at substations are somewhat dependent upon the type of event causing the elevated water level, the main concern is that the design for high water elevation should be based on probability of recurrence plus a safety factor. For example, a utility may select a flood elevation design based on a high-water elevation with a 100-year recurrence interval taken from a FEMA map, plus two (2) feet.

Strategies for dealing with elevated water levels will vary based on whether a substation is new or existing. New substations can have flood control and avoidance built into the initial design of the station, while existing installations will require retrofit.

The following flood control and avoidance strategies can be applied to electrical substations in New Jersey, depending on the needs of the specific site.

4.1.2 Flood Control Strategies

Flood control strategies are designed to keep water out of areas of concern or away from specific equipment. These strategies include the following:

- Install flood walls.[12] Flood walls can be placed to protect large areas or specific pieces of equipment. Flood walls can also be placed inside a building.[13,14] Sandbags can be effective where permanent floodwalls do not exist.
- Install pumping equipment or change existing equipment for higher capacity equipment.[12]
- Provide drainage pathways for water to reach sumps. For example, provide large drains in a control building floor to allow water to easily reach the basement, where it can be removed by pumping.[12]
- Use equipment designed to be completely submerged in basements, vaults or low lying areas.[12]
- Install watertight doors or gates at building entrances.[13]
- Seal all building wall penetrations, both above and below ground.[13]

[12] Interview with Dan Gacek, General Electric Energy Management (GE EM), April 4, 2014
[13] Email from Davis, Kevin, Consolidated Edison (Con Edison), May 14, 2014
[14] Interview with Patrick Murphy, Consolidated Edison (Con Edison), April 22, 2014

There is evidence from the major event reports that EDCs in New Jersey have implemented some of these strategies. For example, in anticipation of possible flooding from Superstorm Sandy, PSE&G reported that they implemented a number of flood control strategies at various substations. Some of these included:

- Double 5-foot reinforced, concrete block wall along with two pumps at New Milford Substation;
- Single 2½-foot reinforced concrete block wall along with two pumps at River Edge Substation;
- Sand bags along with two pumps to protect the control house at Marion Switching Station;
- 4-foot block wall along with one 6-inch high-capacity pump at Somerville Substation; and
- Sandbags on the existing 3-foot concrete wall to a height of five (5) feet at Ewing Substation.

Similar measures were also taken at many other stations.[15] In addition, the EPP Report on the 2011 Major Storms mentions that JCP&L had completed flood gates at the Morristown Substation prior to Hurricane Irene.[16]

4.1.3 Flood Avoidance Strategies

Flood avoidance strategies are designed to keep areas of concern and specific equipment out of the water. These strategies include the following:

- Construct new substations outside of areas of known flood hazard.[17]
- Raise the substation grade. In certain areas, local regulations may not allow net import of fill into a flood hazard area. This strategy is for new stations or for an expansion area at an existing station.[17,18]
- Install sheet pile walls around the substation perimeter. These can be used as flood walls or for fill retention. This strategy may not be suitable for existing stations due to underground obstructions such as conduits.[18]
- Install critical equipment in an elevated position above the design flood elevation, such as control cabinets or auxiliary power transformers.[19]
- Install enclosures or equipment on raised foundations.[20]
- If a multi-story building is used as a substation control building, locate equipment above ground level.[18]
- Install moveable racks for interior panels that allow the racks to be elevated in the event of flooding.[18]

15 PSE&G's Final Report To The BPU Major Event Superstorm Sandy / Nor'easter October 27 - November 15, 2012, February 14, 2013, Page 5 and 6
16 EPP Final Report, "Performance Review of EDCs In 2011 Major Storms," August 9, 2012, Page 112
17 Interview with Jose Santiago, Constellation Energy (BGE), April 22, 2014
18 Interview with Patrick Murphy, Consolidated Edison (Con Edison), April 22, 2014
19 E-mail from Kevin Davis, , Consolidated Edison (Con Edison), May 14, 2014
20 Interview with Charles Christensen, Public Service of New Hampshire (PSNH), April 23, 2014

- For new or replacement installations, install interior equipment, such as modular switchgear or enclosed capacitor banks on elevated foundations.[21]

There is evidence (from discussions and major event reports) that the New Jersey EDCs are aware of some of these strategies and have been implementing them as part of their design standards. For example, after Hurricane Irene, the EPP Report observed that *"ACE's substation design criteria requires mounting equipment above the flood level, and mounting critical relays and protection equipment at least 30" above the relay enclosure floor level."*[22]

4.1.4 Key Recommendations for Substation Hardening

GE recommends the following in order to implement the strategies described above:

1. Add elevation attributes to every flood-prone asset in a substation equipment database; report number of assets below the 100-year flood and storm surge elevation plus 1 foot.
2. Perform limited failure modes and effects analysis (FMEA) for substations using weather events as the modes with customer outages and substation equipment failure as an effect; report findings.
3. Rank findings, estimate and report costs of hardening substation equipment to eliminate the top 20% of equipment failures leading to customer outages as identified in SH-2.
4. Estimate and report costs of regular inspection for critical assets as identified in recommendation SH-2; optimize inspection cycles to achieve highest impact with lowest cost.

Recommendation SH-1: Add elevation attributes to flood-prone assets and report

***Add elevation attributes** to every flood-prone asset in a substation equipment database; **report** number of assets below the 100-year flood and storm surge elevation plus one (1) foot.*

GE recommends that each New Jersey EDC utilize an existing database or create a new database for substation equipment. The EDCs should include elevation attributes for every flood-prone asset and report the number of assets below a defined critical flood elevation. This critical flood elevation could be defined as the 100-year flood elevation or the FEMA advisory base flood elevation plus 1 foot. Flood prone assets are those pieces of equipment that can fail when inundated.

According to PSE&G's "Final Report to the BPU, Major Event, Superstorm Sandy / Nor'easter, October 27 – November 15, 2012," dated February 14, 2013, and EPP's "Performance Review of EDCs in 2011 Major Storms," dated August 9, 2012, several substation equipment failures occurred due to water infiltration during Hurricanes Irene and Sandy, as discussed earlier.

In order to implement this recommendation, each utility will need to collect the following data: elevations of substation equipment or equipment components susceptible to flood damage, and 100-year flood elevation and FEMA advisory base flood elevation at equipment locations. The following are the possible steps toward implementation of this recommendation:

1. Define the critical flood elevation for each substation site.

[21] Boggess, J.M., et. al. "Storm & Flood Hardening of Electrical Substations," IEEE, 2014, pages 3 & 4
[22] EPP Final Report, "Performance Review of EDCs In 2011 Major Storms," August 9, 2012, Page 110

2. Review existing station drawings and/or perform site surveys to determine elevation information for flood prone assets. (Note that no additional implementation steps are required for stations where all flood prone assets are above the critical flood elevation.)
3. Include the elevation date into a Geographic Information System (GIS) database.

The output from this recommendation could include a report of the number and locations of components subject to flood damage that are below the critical flood elevation.

Recommendation SH-2: Perform limited failure modes and effects analysis (FMEA)

***Perform limited** failure modes and effects analysis (**FMEA**) for substations using weather events as the modes with customer outages and substation equipment failure as an effect; **report findings**.*

GE recommends that each New Jersey EDC perform a limited Failure Modes and Effects Analysis (FMEA) for flood-prone assets and report the results of the analysis. The EDCs should perform the analysis using weather events as the modes with customer outages and substation equipment failures as the effect. The results of the FMEA will provide a relative risk of a substation equipment failure. This relative risk can be used to prioritize repairs, modifications, or inspections of flood-prone assets. In order to implement this recommendation, each utility will need to collect the following data: asset elevations data as described in Recommendation SH-1 in this chapter, and definitions of weather events along with the probability of recurrence of each defined weather event.

The following are the possible steps toward implementation of this recommendation.

1. Determine the critical equipment failures and failure combinations that will result in a customer outage.
2. Determine the relative probability of failure for each piece of critical equipment during a defined weather event. For each defined weather event, assign a probability score between 0 and 10 to each piece of equipment, with a score of 0 meaning the equipment will not fail and a score of 10 meaning that failure is certain.
3. Determine the relative severity of failure for each piece of critical equipment during a defined weather event. For each defined weather event, assign a severity score between 0 and 10 to each piece of equipment, with a score of 0 meaning failure of the equipment will not result in a customer outage and a score of 10 meaning that failure of the equipment is certain to result in a severe customer outage. Severity of the outage can be defined as number of customers affected, duration of the outage, or both. The output from this recommendation could include a relative risk score for each piece of critical equipment, and report with analysis of the results.

Recommendation SH-3: FMEA findings, estimate and report hardening costs

***Rank findings**, **estimate** and **report costs of hardening** substation equipment to eliminate the top 20% of equipment failures leading to customer outages as identified in SH-2.*

GE recommends that each New Jersey EDC rank the flood-prone assets based on the relative risk of failure as determined by the results of the analysis described in Recommendation SH-2 in this chapter. The EDCs should estimate and report the costs of hardening substation equipment against the defined weather events in order to eliminate a prescribed percentage of customer outages and equipment failures.

This recommendation is based on the Pareto principle, which indicates that a large percentage of the total available benefit can be realized by implementing a small percentage of the available solutions. As such, protecting, repairing or relocating approximately 20% of the flood-prone assets in substations should eliminate approximately 80% of the outage severity due to flooding and storm surges.

In order to implement this recommendation, each utility will need to collect the following data: asset elevations data as described in Recommendation SH-1 in this chapter and the analysis results as described in Recommendation SH-2.

The following are the possible steps toward implementation of this recommendation:

1. Quantify the number and severity of customer outages that are associated with each potential equipment failure due to flood damage. Consider the relative risk of an outage as determined in the analysis recommended in SH-1, earlier this chapter.
2. Rank equipment failures based on number and severity of outages caused by the equipment failure. Consider the relative risk of each failure as determined in the analysis recommended in Recommendation SH-2 in this chapter.
3. Estimate the costs associated with hardening equipment for a prescribed percentage of the worst ranked equipment. Hardening options include:
   a. Flood avoidance (i.e. vertical relocation);
   b. Flood control;
   c. Equipment relocation;
   d. Retirement of equipment; and
   e. Alternate (backup) supply.
4. Select the desired percentage of equipment to prioritize for hardening considering both the ranking by customer outage and the cost of hardening.

The output from this recommendation could include a prioritized list of substation equipment to harden against flood damage, estimated cost to eliminate the prescribed percentage of customer outages, and the total avoided cost of replacing failed equipment.

Recommendation SH-4: Estimate and report costs of inspection; optimize cycles

<u>Estimate and report costs</u> of regular inspection for critical assets as identified in recommendation SH-2; <u>optimize inspection cycles</u> to achieve highest impact with lowest cost.

GE recommends that each New Jersey EDC estimate and report costs of regular inspections of critical assets. The EDCs should create and implement an inspection program for critical assets or modify an existing program. Inspection cycles should be adjusted on an ongoing basis to achieve the highest impact with the lowest cost.

This recommendation introduces consideration of the risk of storm damage and its impact into planning of maintenance and inspection cycles of utility substations. Inspection and maintenance (I&M) cycles of electrical equipment can be adjusted to account for their criticality during storms. Regular I&M of support structures that are susceptible to storm damage and have significant impact on customers is equally important but may often be overlooked.

In order to implement this recommendation, each utility will need to collect the following data: the analysis results as described in Recommendation SH-2 in this chapter, the assets not selected for hardening from the list of assets as described in Recommendation SH-3 (critical asset list), any existing utility maintenance schedules and procedures for assets to be inspected, and in-service and maintenance records for assets to be inspected.

The following are the possible steps toward implementation of this recommendation:

1. Review any existing maintenance schedules and records against the critical asset list.
2. Develop maintenance procedures for critical assets where existing procedures are unavailable.
3. Estimate the inspection costs for the critical assets in accordance with the defined maintenance procedure.
4. Determine the inspection schedule for the critical assets based on the estimated cost and the rankings as described in Recommendation SH-3 in this chapter.

The output from this recommendation could include inspection criteria for critical assets, an inspection schedule for critical assets, and an escalation procedure for assets that fall below an established criteria threshold.

4.1.5 Capital Cost Estimates for Selected Infrastructure Improvements

GE has chosen to evaluate the costs of eight (8) specific possible infrastructure improvements to substations associated with storm response or damage prevention. These improvements were selected based on ease of installation, applicability across various utilities and applicability to flood control and avoidance. The cost estimates include the cost of design, procurement, and construction for the specific improvement. As noted previously, GE recommends selection of infrastructure improvements for specific New Jersey substations based on the recommendations presented earlier in this chapter.

All cost estimates presented below are general capital cost estimates on a per unit basis for typical installations based on the stated assumptions and GE substation construction estimating experience. Specific products are not noted to avoid the appearance of an endorsement. The estimates do not consider station or utility specific criteria, such as utility standard specifications. The estimates do not consider maintenance or lifetime costs.[23] The estimates were prepared for the sole purpose of evaluating the feasibility of each type of installation. Accuracy of the estimates can be considered as ±25%.[24]

[23] GE estimates include construction costs only because GE does not own or operate electrical substation facilities. Maintenance costs will be determined by the facility owner. Lifetime costs will be based on actual product selected.

[24] These estimates are not pricing proposals or offers of work by GE.

Float Switch Installation

Float switches can be installed in electrical substations to monitor the water level in the substation. They can also be used to monitor the water level within specific installations, such as a containment pit or a basement. Note that float switches themselves will not protect against flooding of substation equipment. Float switches act as indicators that a trouble situation may be imminent and that action may be required.[25] The following assumptions were used to develop the estimate for a float switch installation:

- Three (3) switches mounted on an existing structure or wall.
- Control cable runs from the float switch to an existing trench via conduit.
- Excludes programing of water level points into the existing SCADA system.

Estimated cost: **$22,000**

Metal Clad MV Vacuum Switchgear Installation

Enclosures such as metal clad medium voltage (MV) vacuum switchgear can be used in lieu of air insulated bus to provide for protection of the equipment from wind, windblown debris, and ice. The switchgear can be set on elevated foundations in order to protect against flooding.[26] Metal clad MV vacuum switchgear has the added advantage of having a smaller footprint than air insulated bus, and therefore requires less area for installation. The following assumptions were used to develop the estimate for a metal clad MV vacuum switchgear installation:

- The installation is a seven-bay 34.5 kV metal clad indoor switchgear, with breakers & relays.
- The P&C control panels are for two (2) transformer bays, two (2) HV bays, one (1) bus differential bay, and one (1) communications panel.
- The installation includes a 200 amp-hour 20 year battery.
- The exterior plan dimensions are 20 ft. x 60 ft.
- The switchgear is elevated to 4 ft. above grade by extending the concrete foundations.
- The switchgear is founded on eight (8) spread footing foundations, with the bottom of the footings located 4 ft. below grade.
- The switchgear is supported by eight (8) circular concrete columns, 3 ft. in diameter, with 2 ft. x 2 ft. concrete beams running around the perimeter of the building and at two intermediate locations across the building short direction.
- Crane rental and building placement is included.
- Commissioning and startup is included.
- Excludes installation of cables to field equipment.

Estimated cost: **$2,802,000**

[25] Boggess, J.M., et. al. "Storm & Flood Hardening of Electrical Substations," IEEE, 2014, page 3

[26] Boggess, J.M., et. al. "Storm & Flood Hardening of Electrical Substations," IEEE, 2014, pages 3 & 4

Pump Change Out

As noted in Section 4.1.2, existing pumps can be exchanged for higher capacity pumps to allow for a greater pumping rate.[27] The following assumptions were used to develop the estimate for changing to higher capacity pumps:

- Two (2) 600 gallon per minute pumps are installed in an existing sump pit. Existing drainage system with check valves conveys water to sump.
- Install a new pump panel, connected to new wiring.
- Install four (4) float switches for automated pump control.
- Install 50 ft. of 6-inch diameter steel pipe, with five (5) 90° pipe elbows and one (1) pipe tee.
- 480 volt AC power is available and adequate from spare breaker(s) in the AC panel.

Estimated cost: **$40,000**

Automatic Transfer Switch

Automatic transfer switches (ATS) can be used to regulate the source of auxiliary power for a substation (feeder, transformer tertiary, station service transformer, backup generator, etc.). The following assumptions were used to develop the estimate for the installation of an ATS:

- ATS is four pole, 480 V, 65 kA, 200 A rated.
- Supports load to lighting, battery chargers, station auxiliaries, and two (2) 30 kW sump pumps.
- ATS is placed within 100 ft. of either source.

Estimated cost: **$46,000**

Flood Walls

As noted in Section 4.1.2, flood walls can be installed to protect critical equipment. Critical equipment can include a control building.[28] The following assumptions were used to develop the estimate for the installation of a flood wall around a building:

- Building exterior dimensions are 50 ft. x 20 ft., with flood wall placed at 6 ft. clear from building.
- The flood wall extends 3 ft. above grade.
- The flood wall is constructed of 6 inch thick reinforced concrete.
- Cable ducts through or under the wall are sealed.
- Installation includes one (1) set of stairs over the flood wall.
- Installation includes one (1) removable steel panel to allow equipment through the wall.
- The installation includes a duplex pump system installed in an exterior vault.

Estimated cost: **$319,000**

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[27] Interview with Dan Gacek, April 30, 2014
[28] E-mail from Kevin Davis, May 14, 2014

Raise Existing Interior Control Cabinets and Racks

As noted in Section 4.1.3, critical equipment can be installed or moved to an elevated position. This critical equipment includes cabinets and racks inside control buildings.[29]

The following assumptions were used to develop the estimate for raising existing interior cabinets and racks:

- Raise cabinets and racks 1 ft.
- Raise a total of ten (10) items.
- All cables are currently routed through a trench or basement below the equipment.
- Replace 750 interior cables; each cable is 30 ft. long.
- Cables having a termination outside of the building (yard cable) are currently connected to an existing indoor termination cabinet that will not be raised. These cables will not be replaced.
- Each piece of equipment is supported by a steel stand weighing 100 lbs. per stand.
- Adequate clearance exists between top of equipment and building ceiling.
- Existing wiring terminations are labeled.

Estimated cost: **$107,000**

Raise Exterior Equipment

As noted in Section 4.1.3, critical equipment can be installed or moved to an elevated position. This critical equipment includes high voltage breakers.[30]

The following assumptions were used to develop the estimate for raising one (1) existing high voltage breaker.

- The breaker is connected to a 230 kV bus.
- The breaker is raised 2 ft. – 3 in.
- A steel adaptor frame is installed between the foundation and the breaker support frame.
- The installation includes an elevated operating platform for cabinet access.
- The installation includes replacement of control cables. Each control cable will be 100 ft. long.
- The breaker is connected to the bus via power cables. Each cable is 10 ft. long.

Estimated cost: **$43,000**

[29] Interview with Patrick Murphy, April 22, 2014
[30] Interview with Patrick Murphy, April 22, 2014

Site Grading

As noted in Section 4.1.3, the grade at the site of a proposed substation can be raised to provide a higher substation surface elevation.[31]

The following assumptions were used to develop the estimate for raising the grade for a new substation.

- The proposed substation site is raised 3 ft.
- Site area is 200 ft. x 400 ft.
- Inches of existing surface material (organic layer) is stripped & removed from site (clear & grub).
- The existing soil at 6 inches depth is suitable for use as subgrade. Subgrade is compacted.
- All stripped material is hauled and disposed as non-hazardous waste.
- All fill is imported from off site.
- Fill material is spread and compacted in 8-inch thick loose lifts.
- The edge of the graded area is sloped to existing grade; retaining walls are not required.
- Excludes blasting, paving of access roads, ditches, berms, fence and gates, and associated water retention requirements.

Estimated cost: **$482,000**

4.1.6 Summary of Strategy Costs and Compatibility

The cost estimates presented in this report are summarized in Table 4-1 below. Table 4-2shows which of the eight (8) strategies for which estimates were prepared can be implemented in parallel.

Table 4-1 Cost Estimate Summary

Strategy	Applicability	Cost Estimate
Float Switches	New or Existing Station, Used for Monitoring	$22,000
Metal Clad MV Vacuum Switchgear	New or Existing Station, New Switchgear Installed in Elevated Position	$2,802,000
Duplex Pumps	Existing Station, Replace Existing Equipment	$40,000
Automatic Transfer Switch	New or Existing Station	$46,000
Flood Walls	New or Existing Station	$319,000
Raise Racks	Existing Station, Interior Equipment	$107,000
Raise Equipment	Existing Station, Exterior Equipment	$43,000
Grade Site	New Station, Raise Entire Site	$482,000

[31] Interview with Jose Santiago, April 22, 2014

Table 4-2 Strategy Compatibility

	Float Switches	Metal Clad MV Vacuum Switchgear	Duplex Pumps	Automatic Transfer Switch	Flood Walls	Raise Racks	Raise Equipment	Grade Site
Float Switches		●	●	●	●	○	○	○
Metal Clad MV Vacuum Switchgear	●		●	●	●	●	●	●
Duplex Pumps	●	●		●	●			
Automatic Transfer Switch	●	●	●		●	●	●	●
Flood Walls	●	●	●	●		-	-	-
Raise Racks	○	●	-	●	-		●	-
Raise Equipment	○	●	-	●	-	●		-
Grade Site	○	●	-	●	-	-	-	

● Indicates strategies are fully compatible

○ Indicates strategies may be compatible on a case-by-case basis

- Indicates strategies are redundant

4.2 Back-Up Power for Substations and Central Offices

4.2.1 Substations

Power transmission and distribution substations are equipped with electronic controls, for remote monitoring, switching, communications and protection systems. These controls are powered by a direct current (DC) power supply system. This DC power supply system includes a battery or series of batteries (depending upon the requirements of the substation's electronic controls) and a battery charger. Under normal operation, the batteries supply the substation's DC power requirements, the battery charger provides a continuous power supply to the batteries, and the alternating current (AC) transmission or distribution circuits entering the substation provide a continuous power supply to the battery charger. Should the battery charger fail or the AC circuit supplying the substation be curtailed, the battery must have the ability to support the load of the substation's electronic controls until the battery charger is repaired or the AC supply to the substation is restored.[32]

Typically, the size or capacity of the battery is based on the profile of continuous, intermittent, and momentary substation control system loads during the outage of the battery charger and/or the AC supply.

[32] It is considered to be good utility practice for transmission owners and/or utilities to routinely maintain and test the DC power supply system including the battery and battery charger, to help ensure system performance.

According to GE engineers, these battery systems are generally designed to support the substation's control systems loads without the battery charger and/or AC supply for a period of up to eight (8) hours (although no North American Electric Reliability Corporation (NERC)[33] reliability standard or requirement specifying the minimum required time period duration could be located).

Once the battery supporting the DC power supply system in the substation has been discharged to the point where the substation controls are compromised, the control systems (monitoring, switching, communications, and protection) cannot function until the battery charger and/or AC supply to the substation is able to restore power to the battery and the DC power supply system.

In reviewing publicly-available reports and documents describing electric utility recovery following major storms, including the EDC MERs supplied by the BPU, there were several reported incidents of damage to substation batteries in New Jersey. During Hurricane Irene, for example, PSE&G's Somerville and New Milford substations suffered damage to the station batteries.[34] Also, during Hurricane Sandy, PSE&G reported that at the Linden switchyard, the "*138kV breakers and control cabinets, battery chargers and relay equipment [were] damaged*." Additionally, there were battery charger failures at Essex switchyard and Jersey City switchyard. The station battery, DC and AC control systems were damaged at Marion switchyard, and the station battery and relay equipment were damaged at St. Paul's Avenue substation.[35] However, GE did not find evidence in the reports to suggest that substation battery or battery charger failure *alone* was the underlying cause for customer service interruptions.

This should not imply that substation battery or battery charger failure has not led directly to customer interruptions, but rather that it was not documented in the reports as an underlying cause for customer service interruptions.[36]

According to GE engineers, it is not uncommon for utilities or transmission owners to include an on-site auxiliary or back-up generator in the substation design, engineering, and construction when that substation is deemed to be a critical or key component for normal operations and for system restoration. For those critical substations, when the AC power supply to the substation is interrupted, the back-up generator can be started automatically and continue to provide power to the battery charger so that substation controls continue to function while system restoration is underway. The size of the back-up generator is determined by the requirements of the DC power supply system and any additional loads at the substation which the utility or transmission owner need to support when the AC power supply is interrupted.[37]

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[33] The North American Electric Reliability Corporation is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. http://www.nerc.com/Pages/default.aspx.

[34] EPP Final Report, "Performance Review of EDCs In 2011 Major Storms," August 9, 2012, Page 113.

[35] PSE&G's Final Report To The BPU Major Event Superstorm Sandy / Nor'easter October 27 - November 15, 2012, February 14, 2013, Page 13.

[36] In conversations between GE and the BPU, the BPU Staff "could not recall" an incident where lack of DC power to a substation rendered a substation inoperable and led to, or extended customer interruptions.

[37] Consistent with the substation DC power supply system that these generators are installed to support, it is considered to be good utility practice for transmission owners and/or utilities to routinely maintain and test the back-up generators and associated equipment and fuel system to help ensure their availability and performance during system emergency conditions.

While back-up generators are the more common form of supplemental power source for substations, other alternatives are available. It may also be possible to install additional batteries or fuel cells to extend the period of time that the DC power supply system may function during an AC power supply interruption. However, these alternatives may not offer the flexibility, familiarity, or cost advantages that back-up generators can offer.

Cost Benefit Analysis Discussion

In this subtask, the first step was to review other studies focused on cost-benefit analysis of installing back-up power at substations. The most recent example of this type of analysis that GE was able to identify was a 2009 report completed by Quanta Technologies for the Public Utilities Commission of Texas (PUCT) which evaluated the cost and benefits (utility and societal) of deploying utility infrastructure upgrades and storm hardening programs along the Texas Gulf Coast region. The Quanta Report states that the following:[38]

> *"Benefits derived from backup station power are dependent upon the nature of the outage. If transmission service to the substation is interrupted, auxiliary power is less beneficial. If line protection and communications must be maintained from a particular substation, backup power is critical and is normally supplied by the batteries … auxiliary station service power is of primary benefit for a station service supply outage. When the entire substation is out of service due to internal damage or transmission line damage, the benefit of backup station service power is lessened."*

In each station damage incident reported by PSE&G during Hurricanes Irene and Sandy[39] (listed earlier) there were multiple pieces of equipment that were flooded and damaged (beyond the batteries and battery chargers) which impacted the stations' ability to provide service. In these cases, backup power for the DC supply would not have been immediately effective in restoring the stations functionality. The Quanta Report presents a macro-level cost benefit analysis based on several assumptions about adding emergency generators to substations (although no basis for these assumptions was included in the report). The assumptions were:[40]

- Substation damage incidents reported are assumed to require backup power beyond the existing substation capability 30% of the time.
- Avoided cost is based on the reduction of substation service power outage by one-half day and valued at daily [Gross Domestic Product] rate for the area.
- Generator cost assumes generator capacity capable of full backup of station service with an automatic transfer switch.

[38] Brown, Richard. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Quanta Technologies. Prepared for Public Utility Commission of Texas, Project No. 36375. March 4, 2009. Pages 49-52. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf.

[39] PSE&G's Final Report To The BPU Major Event Superstorm Sandy / Nor'easter October 27 - November 15, 2012, February 14, 2013, Page 13

[40] Brown, Richard. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Quanta Technologies. Prepared for Public Utility Commission of Texas, Project No. 36375. March 4, 2009. Page 50. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf.

Given these assumptions, the Quanta Report concluded that broad deployment of minimal back-up generation (10 kW) at the 1,088 substations[41] located within 50 miles of the Texas Gulf Coast was not cost effective. While the Quanta Report did state that a more detailed analysis at the individual substation level is needed to "*appropriately assess cost and benefits*," it nevertheless concluded that "*Considering the level of backup power already available in a typical substation and the low incidence of loss of station power (even in storm conditions)*" there is likely no incremental benefit to installing additional back-up power at substations.[42]

It may be possible to perform a similar macro-level cost-benefit analysis for New Jersey, based on a series of macro-level assumptions for both costs (installed cost, operation and maintenance costs, fuel costs) as well as benefits (resiliency, utility and societal benefits). However, the economics of installing back-up generators for substations can vary significantly from one substation to another, both in terms of the installed and operating costs, and the system benefits (restoration, minimizing social and economic impacts) that could result.

As of May 15, 2014, there were 512 substations in New Jersey, ranging in size from small distribution substations (4kV) to large transmission substations (500kV).[43] It is assumed that each of these substations contains a DC power supply with batteries capable of supporting the substation communications, controls and protection for up to eight (8) hours.

However, it is not known how many of these substations currently have back-up generators installed on-site (or planned), or which substations are considered to be critical for system restoration to minimize utility, social and economic impacts under various catastrophic event scenarios.

Ideally, it may be preferable to look at each individual substation without a back-up generator on-site and estimate the site-specific costs of installing a generator and a secure fuel supply. Given that a cost-benefit analysis at each individual substation in New Jersey is beyond the scope of this study, GE has identified the following cost assumptions for a 300 kW back-up generator[44] suitable for installation at a "typical" substation.

[41] In the Quanta report, there were a total of 1,094 substations in the area under consideration, and back-up generators were already installed at 6 substations.

[42] Brown, Richard. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Quanta Technologies. Prepared for Public Utility Commission of Texas, Project No. 36375. March 4, 2009. Page 50. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf.

[43] Ventyx Velocity Suite database. Ventyx, an ABB Company.

[44] 300 kW generator size is an approximation, based GE proprietary substation design for a New Jersey client (450 kW) and publicly-available cost and performance data for distributed generation technologies. Each individual substation will likely have specific back-up generator size requirements.

Table 4-3 DG Technology Cost and Performance Data

Distributed Generation Technology	
$1,784	/kW Installed Cost for 300 kW Oil-Fired Engine Generator, installed in 2010 (2009 $/kW) US Department of Energy, Energy Information Administration. 2014 Annual Energy Outlook. Commercial Demand Module. http://www.eia.gov/forecasts/aeo/assumptions.pdf/commercial.pdf
10,029 Btu	/kWh assumed "*Distributed Generation – Peak*" heat rate US Department of Energy, Energy Information Administration. 2014 Annual Energy Outlook. Electricity Market Module Assumptions, Table 8.2 http://www.eia.gov/forecasts/aeo/assumptions.pdf/table8_2_2014er.pdf
$7.76	/MWh for "*Distributed Generation – Peak*" Variable Operation $ Maintenance cost assumption (2012 $/MWh) US Department of Energy, Energy Information Administration. 2014 Annual Energy Outlook. Electricity Market Module Assumptions, Table 8.2 http://www.eia.gov/forecasts/aeo/assumptions.pdf/table8_2_2014er.pdf
$17.45	/MWh for "*Distributed Generation – Peak*" Variable Operation $ Maintenance cost assumption (2012 $/kW-yr) US Department of Energy, Energy Information Administration. 2014 Annual Energy Outlook. Electricity Market Module Assumptions, Table 8.2 http://www.eia.gov/forecasts/aeo/assumptions.pdf/table8_2_2014er.pdf
$29.25	/MMBtu Diesel fuel cost based on 2013 average central Atlantic cost of Low S Diesel (2013 $/MMBtu) US Department of Energy, Energy Information Administration. Central Atlantic (PADD 1B) Gasoline and Diesel Retail Prices. http://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_r1y_a.htm

It should be noted that the dollar per unit (or $/kW) installed costs can vary for smaller back-up generators, based on a number of factors, including the kW size of the engine generator, the on-site requirements and the interconnection configuration.

As an example, GE's Waukesha gas engine product line includes a small engine to power a 310 kW generator, and the estimated current cost for the engine only (without generator) is between $450 and $500/kW. Additional costs for the generator and complete packaging could raise the total cost to about $1,000/kW,[45] plus on-site requirements and interconnection configuration.

Once the installed costs and operating costs for back-up generators have been estimated, a bigger challenge lies in identifying and estimating the potential system restoration benefits of minimizing or avoiding utility costs, societal costs, and economic impacts as a result of having installed a back-up generator at that specific substation. Not all major storms or catastrophic events (hurricanes, tropical storms, tornados, blizzards, earthquakes, etc.) would impact the electric power system in the same way. Some regions of New Jersey may be more impacted than others (coastal vs. inland, northern vs. southern, etc.) under a similar or different circumstance.

Questions that will need to be addressed or resolved for a macro-level cost-benefit analysis include:

[45] Based on interview with Tony Mente, Application Engineer, GE Power & Water, Distributed Power, August 18, 2014.

- What is the probability of a major storm or catastrophic event occurring at various locations in New Jersey? Once in 5 years? Once in 10 years? Once in 100 years?
- What is the appropriate measure or index of the benefit of installing back-up generators at substations? Total customer outage time? Lost electricity consumption? The societal Value of Lost Load (VOLL) for extended outages? Lost economic activity (State Gross Domestic Product) as a result of extended outages?
- What other benefits or avoided costs should be considered, and how should each be measured and quantified? Customer dissatisfaction or inconvenience due to extended outages or interruptions? Adverse effects to public health and welfare impacts due to extended outages or interruptions during extreme weather conditions (winter or summer)?

Questions such as these should be considered and resolved (to the extent possible) when evaluating the costs and benefits. The answers or outcomes as well as the range of uncertainty surrounding answers to these questions can easily overwhelm the uncertainty inherent in other inputs and assumptions needed for to the valuation (capital and O&M costs, inflation and escalation, discounting, etc.). This is especially true for major storms or catastrophic events with a low probability of occurrence but a high impact when they occur.

4.2.2 Central Offices (Communication Facilities)

As directed by the BPU, the scope of this work was limited to the electric distribution companies (EDCs) in New Jersey. Since telecom utilities were not explicitly in the scope, the discussion of "Central Offices" as stated originally in the BPU scope (see introduction to this chapter) has been generalized to a discussion of the role of electric utility "communication facilities" during storms.

Communications During Storms

During and after major storm or catastrophic event, it is critical for utilities to maintain continuous communications with customers and field operations (central stations, substations, transmission and distribution field crews) during the grid restoration process. From a reliability perspective, the NERC Standard COM-002-2 (Communications and Coordination) states the following: [46]

> *"Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition."*

Communications within the distribution utility needed to manage and coordinate the storm response is one of those things that are often taken for granted, and critically missed when it is gone. Poor or no internal communications can potentially hobble the entire restoration effort.

During a storm, many modes of communication are used to report emergencies, keep families and off-duty personnel up-to-date, maintain contact with customers and suppliers, and coordinate response actions. These systems include cell phones, beepers/pagers, radios, telephones and faxes, and computer networks.

[46] NERC Standard COM-002-2 — Communications and Coordination, Section B. Requirements, subsection R1 (effective date January 1, 2007).
http://www.nerc.com/files/COM-002-2.pdf

Conversations with utilities have confirmed that the primary means of communication with crews and other responders are two-way radios, cell phones, remote data terminals, and in some cases satellite phones. Not surprisingly, there is more reliance on private networks than on public or commercial services during emergencies, because experience has shown that private networks are more reliable during major storms.

A study by UTC Research examined the reliability of internal communication networks during the 2005 hurricane season. According to the report:[47]

> *"... storms Katrina, Rita and Wilma pointed out the weaknesses in many ... critical infrastructures, including telecommunications networks, some of which [were] still recovering months after the storms. However, in sharp contrast to many commercial wireless, landline telephone and other telecommunications networks, the private, internal networks (radio, microwave and fiber) of electric, gas and water utilities for the most part continued to function throughout and immediately after the storms. In some cases, it was utility communications networks that provided the only reliable communications among emergency responders and other officials during the first few days after the storms."*

In many cases, utilities do not own or operate the communication network, but may lease capacity or contract service from a third party.

During a major storm, when demand is high, not only from the utility but from the general population as well, and supply is low due to infrastructure damage, it is critical that the utility has control over vital communication networks, especially those used to coordinate the restoration.

During Hurricane Andrew, FPL learned, "*if you want to depend on a system, be sure it is a system that your personnel can restore to service*."[48] They discovered that the communication systems owned by the utility performed well, while systems they did not control were unreliable or unavailable. Another utility subject to major hurricanes, Southern Company, has reported that the company-owned wireless communications network, SouthernLINC, plays a major role in their restoration effort. In fact, during Hurricane Katrina in 2005, the only viable communication channel Mississippi Power had available to coordinate over 10,000 external personnel and 30 staging sites was the SouthernLINC system.

Even though utilities' private communication systems tend to be more resilient than commercial systems, it is good practice to have backup systems should the in-place network become inoperable. During the 2005 hurricanes, there were some incidents of tower damage and outages that compromised utilities' fixed communications systems. As a backup in these types of situations, some utilities deploy mobile towers and satellite communications trailers that can be easily transported to remote sites for first response communications deployment.

A Southern Company communications trailer is shown in the image to the right. This particular trailer includes a satellite communications

[47] United Telecom Council, Hurricanes of 2005: Performance of Gulf Coast Critical Infrastructure Communications Networks, November 2005

[48] Kaplan, L. G., Emergency and Disaster Planning Manual, McGraw-Hill, 1996

package: iDirect modem and Automatic Vehicle Location (AVL) control panel, wireless access, Voice over IP, VPN functionality, and other customized solutions. It also includes a radio system that works through the satellite system to communicate between the trailers and the storm center. The trailer is powered with a diesel genset, and is light enough to be pulled behind a heavy-duty pick-up truck, such as a Ford F-250.[49]

Cost Benefit Analysis Discussion

The Quanta Report (mentioned earlier) also includes a macro-level cost-benefit analysis of installing back-up generation at telecom central office locations along the Texas Gulf Coast; no other recent publicly available studies of installing back-up generation at utility central offices were identified by GE.

The analysis performed by Quanta included the following assumptions, although no basis was provided for each:[50]

- Current central office locations have available space to accommodate installation of a generator and fuel supply.
- The incidence of utility power outage is 50% of the damage rate reported by the telephone companies.
- Avoided cost is based on reduction of central office power outage by one-half day and valued at daily GDP rate for the area.

While the present value of utility costs and social benefits in the Quanta Report did not support installation of back-up generators at substations, the report did conclude favorably for backup generation at telecom central offices:[51]

> *"Although this macro analysis does not result in a positive net present value, the annual hurricane benefits of [sic] compare favorably with the program cost. However, the analysis assumes that 20% of [central offices] do not have any backup generation capability. In reality, these [central offices] are supported by mobile backups which currently supply most of these benefits."*

However, a large portion of the benefits cited by Quanta hinged on the societal value of communications service to customers, which is the primary role of a Telecom CO, but not the primary function of a utility communications node.

Utility communications during storms are deployed to control and coordinate the restoration effort. Therefore the value of backup generation to utility communications nodes has a secondary effect on society, i.e. it impacts restoration time, which in turn accrues to societal benefits. Private utility

[49] Specifications provided courtesy of Southern Company, Alabama Power in conversation with GE

[50] Brown, Richard. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Quanta Technologies. Prepared for Public Utility Commission of Texas, Project No. 36375. March 4, 2009. Page 51. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf.

[51] Brown, Richard. "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs." Quanta Technologies. Prepared for Public Utility Commission of Texas, Project No. 36375. March 4, 2009. Page 52. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf.

communication systems are already generally more resilient than public systems, (as discussed earlier), and most utilities with private networks have contingency plans in place in the event of their failure (mobile towers, communications trailers, satellite phones, public systems).[52]

It may be possible to perform a similar macro-level cost-benefit analysis for New Jersey EDC communication facilities, using the back-up generator cost and performance data presented in Table 4-3 above and data on the number of New Jersey EDC communication facility locations without back-up power for extended outage periods and their power requirements. Similar to substations, a more significant challenge lies in identifying and quantifying the benefits of installing back-up generators at EDC communication facilities, and the ability to assign societal benefits to the resiliency of each EDC communication facility. Some of the same questions (highlighted earlier for substations) will need to be addressed or resolved for a macro-level cost-benefit analysis of backup power at utility communication facilities.

4.2.3 Key Recommendations for Backup Power

Earlier in Section 4.1.4, GE presented several recommendations for substation hardening. The FMEA and ranking process outlined in Recommendation SH-2 and Recommendation SH-3 are designed to expose whether substation DC power failure during weather events is a driver of substation unavailability. If the FMEA from Recommendation SH-2 reveals that battery backup is indeed a failure mode, then backup power or alternate supply to the battery charger will be one of the hardening options considered in Recommendation SH-3. Therefore, to avoid redundancy, this section does not include a separate recommendation for backup power for substation DC controls.

Based on the discussions above, GE recommends the following actions for the EDCs:

1. Identify and report communications facilities critical to restoration process; estimate and report costs of providing backup power to cover 3-sigma of expected storm restoration time.
2. Require EDCs to include quick deployment of mobile substations and mobile backup generator equipment in emergency response plans for various catastrophic events across NJ.

Recommendation SH-5: Identify critical communication facilities; estimate hardening costs

Identify and report communications facilities critical to restoration process; estimate and report costs of providing backup power to cover 3-sigma of expected storm restoration time.

Based on recent history, storm-related outages can last from a few hours to over a week. Communication facilities are a high-priority restoration target, but it may still take several hours to restore power after a storm. This recommendation will inform the BPU as to how much backup power is needed at communication facilities to maintain command and control during a prolonged outage.

GE recommends that the New Jersey BPU require EDCs to identify which communication facilities are critical for: (1) maintaining communications with other EDCs, transmission owners, grid operators and regional reliability coordinators, as well as state and local regulatory authorities,

[52] Based on a survey of utility members of the DSTAR consortium (www.dstar.org).

retail customers and the media; and (2) conducting and coordinating field operations (substations, transmission, distribution) for grid restoration.

This recommendation requires that the EDCs install adequate back-up generators at each of their business-critical communication facility locations with sufficient and secure on-site fuel storage capacity to support an adequate period of generator operation, after which time additional fuel supply can be delivered to the site. Historical power outage data should be analyzed, to determine the average or mean power outage duration, and the "3-sigma" statistic (see Figure 4-1)[53] should be estimated to determine the number of hours of operation that both the back-up generator and the secure on-site fuel storage should accommodate.

In keeping with this recommendation, GE expects that each EDC will develop and apply customary back-up generator maintenance and testing schedules to ensure back-up generator reliability.

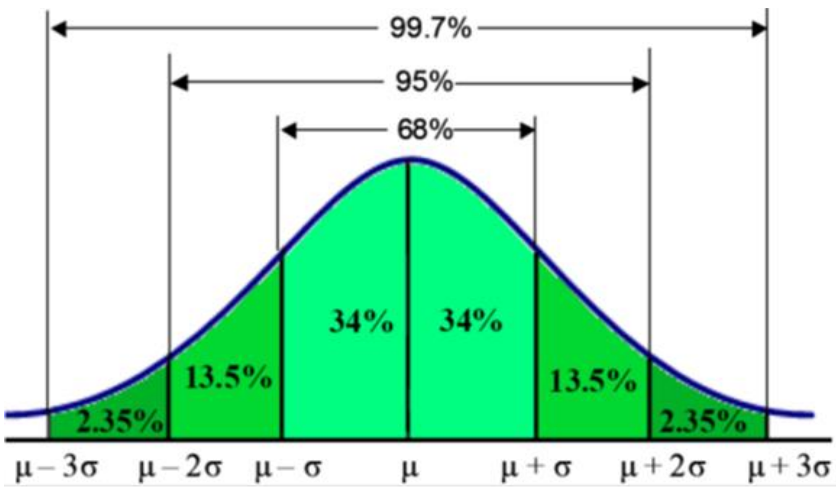


Figure 4-1 Relationship between sigma and area under normal distribution curve

In order to implement this recommendation, each utility will need to collect the following data:

- List of communications facilities critical to the restoration process;
- Existing backup power configuration/procedure, (batteries, diesel, gas, combination, fuel supply/acquisition);
- Historical duration of major storms and time to restore power to critical communication facilities;
- Backup generator configuration needed to cover "3-sigma" of storm outage duration. Example: secure on-site fuel storage for one day; replenish fuel supply on day two after outage; daily supply thereafter as necessary.

The following are the possible steps toward implementation of this recommendation:

---

[53] For data which is normally distributed, the "3-sigma" or 3σ statistic represents the percentage of observations that fall within ± three (3) standard deviations of the mean, or approximately 99.73% of all observations. In this application, "3-sigma" of storm outage duration would be the restoration time for communication facilities during storms 99.73% of the times.

1. Determine statistical period that covers 3-sigma of communication facility outages during past storms
2. Estimate the configuration and cost of backup generation to cover 3-sigma period (installed cost, fuel, O&M).
3. Identify communication facilities critical to restoration process with insufficient backup for 3-sigma duration
4. Estimate costs to upgrade communication facilities backup power supply to cover 3-sigma of storm restoration duration

Step 1 above would consist of reviewing historical storm restoration times and tabulating the actual outage times for communication facilities during each storm. This would create a dataset from which the standard deviation (sigma) and consequently the 3-sigma outage time can be computed.

The 3-sigma outage time defines the threshold for restoring most facilities. For example, if the distribution of restoration times is normal[54] then then 3-sigma is the time it takes to restore communication facilities 99.7% of the time.

The output of this process would include EDC plans for backup power at critical communication facilities, locations, configuration, size and cost of backup power supply, amount of secure on-site fuel storage (at full load operation), maintenance plan & schedule, contingency plans.

Recommendation SH-6: Require quick deployment of mobile subs and backup gens

Require* EDCs to include *quick deployment of mobile substations and mobile backup generator equipment in emergency response plans for various catastrophic events across NJ.

At the time the August 2012 EEP report was published, JCP&L had fifteen (15) mobile substations available for deployment (EEP Report, page 112), PSE&G had ten (10) mobile substations available (with additional units being acquired) (EEP Report, page 114), Orange & Rockland had five (5) mobile substations (EEP Report, page 115).

In its February 2014 Superstorm Sandy Report (page 14), PSE&G stated that it contracted for sixteen (16) large portable generators, which it deployed at a PSE&G office building, switching station locations and other essential utility, hospital and correctional facilities in the area.

GE recommends that the NJBPU require the EDCs to consider including quick deployment of an adequate number of both mobile substations and mobile back-up generator equipment in emergency response plans for various catastrophic events across NJ.

A similar process defined above, for backup generation at communications facilities, can be used to determine the statistical period for which mobile substations and mobile backup generator equipment are needed before the system can be restored.

[54] This is just an illustrative example as there is no reason to suspect that the distribution of restoration times is normal; in fact it's more likely to be skewed to the right i.e. many cases of quick restoration and a few cases of prolonged restoration.

5 REVIEW OF SMART GRID & DISTRIBUTION AUTOMATION INITIATIVES

5.1 Background of Smart Grid and Distribution Automation

In this section GE presents the background of federal and U.S. industry-led initiatives, including available results from the US DOE and EPRI Smart Grid pilots. Section 5.2 summarizes key findings from a review of the literature on the current state of SG-DA and related technology and emerging applications for storm resiliency, with particular attention to the Northeast states and other storm-prone regions of the U.S.

Sections 0 and 5.4 presents the review of the New Jersey EDC filings, particularly with regard to compliance with BPU orders 63 and 65 and the requirement for information on timelines, costs, and benefits of the EDCs' SG-DA plans. Throughout the chapter, SG-DA recommendations for BPU action are highlighted.

5.1.1 EISA and the ARRA Funded Pilot Experience

Title XIII of the Energy Independence and Security Act (EISA) of 2007 states:[1]

> *"It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:*
>
> 1. *Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.*
> 2. *Dynamic optimization of grid operations and resources, with full cyber-security.*
> 3. *Deployment and integration of distributed resources and generation, including renewable resources.*
> 4. *Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.*
> 5. *Deployment of "smart" technologies (real time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.*
> 6. *Integration of "smart" appliances and consumer devices.*
> 7. *Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.*
> 8. *Provision to consumers of timely information and control options.*
> 9. *Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.*
> 10. *Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services."*

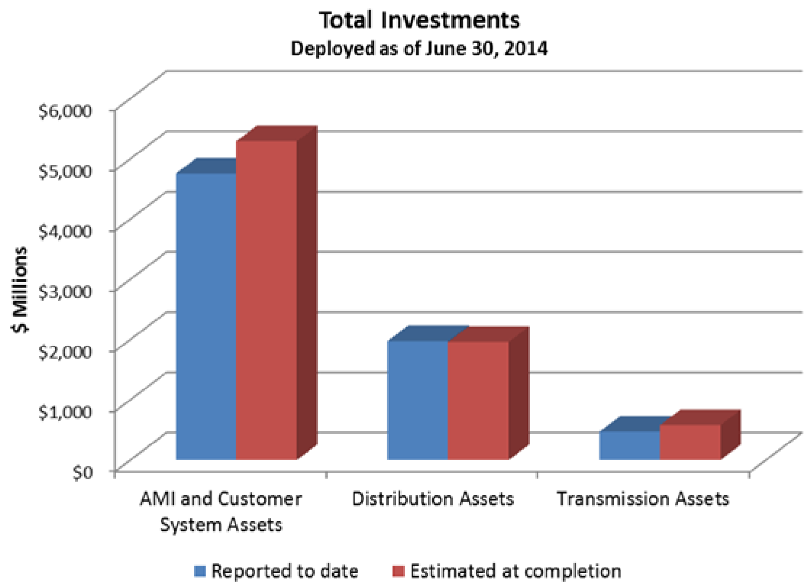
[1] EISA Section 1301, http://www.ferc.gov/industries/electric/indus-act/smart-grid/eisa.pdf

The American Recovery and Reinvestment Act (ARRA) of 2009 provided the U.S. Department of Energy with $4.5 billion to modernize the electric power grid and implement Title XIII of EISA. With matching utility funding for many programs, the total investment in Smart Grid resulting from ARRA is expected to reach $7.9 billion.

Under ARRA, the U.S. Department of Energy (DOE) is responsible for tracking the status of investments made through the Smart Grid Investment Grant (SGIG) Programs and Smart Grid Demonstration Programs (SGDP). The DOE maintains the smartgrid.gov website to track progress in the resulting investment programs.

Figure 5-1 and Figure 5-2 show assets implemented through the two programs by the type of system. Assets include hardware, software, and applications that enable Smart Grid functions.

The site also shows equipment that is installed and operational to date. The dollar figures are the total project costs funded by the government and utilities.

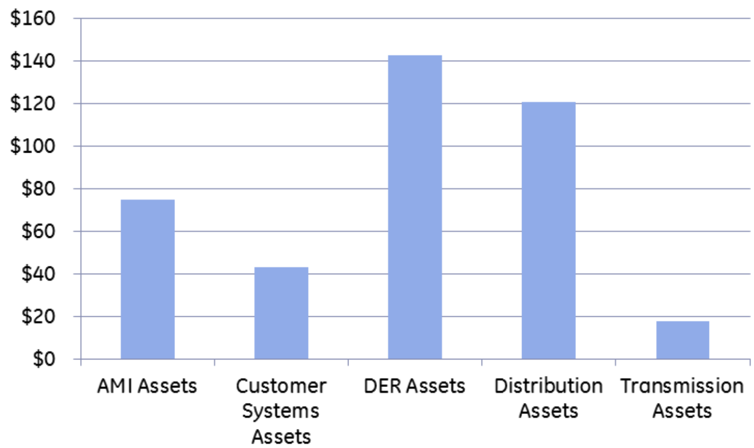


Source: https://www.smartgrid.gov/recovery_act/deployment_status

Figure 5-1 Total SGIG Investment by Asset Category

Smart Grid Investment Grant (SGIG) Programs:

- Peak Demand and Electricity Consumption
- Operational Improvements from Advanced Metering Infrastructure (AMI)
- Operational and Maintenance Improvements in Distribution Systems
- Reliability Improvements in Distribution Systems
- Energy Efficiency Improvements in Distribution Systems
- Synchrophasor Applications in Transmission Systems



Source: https://www.smartgrid.gov/recovery_act/deployment_status

Figure 5-2 SGDP Investment by Asset Category

Smart Grid Demonstration Programs (SGDP)

- Regional Demonstration Projects: to assess the integration of advanced technologies with existing power systems including those involving renewable and distributed energy systems and demand response programs.
- Energy Storage Demonstration Projects: to demonstrate a variety of technologies including advanced batteries, flywheels, and underground compressed air systems. The projects are demonstrating a variety of size ranges, system configurations and their impact on the grid.

The DOE publishes regular updates on the progress of investments funded under the ARRA Smart Grid program. The most recent annual report on the SGIG Programs from October 2013 provides a snapshot of reported results to date.[2]

Of the total ARRA investment, $1.96 billion was directed towards distribution system equipment (not including Advanced Metering Infrastructure (AMI) and customer-side technologies) in 57 projects.

Forty-eight of these projects are targeted at reliability improvement and the other projects include investments in conservation voltage reduction (not specifically aimed at improving reliability). Collectively, these projects have installed 7,661 automated switches and 11,102 automated capacitors, as well as associated communications and data management.

In December 2012, the DOE published initial results in the reliability-oriented Smart Grid Distribution Automation (SG-DA) programs[3,] highlighting the direct benefits in terms of outage reduction available with many technologies. Quantitative results were provided from four projects (covering a collective 1,250 circuits).

[2] SGIG Progress Report II, US DOE, October 2013. (available at smartgrid.gov)

[3] Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results, US DOE, December 2012. (available at smartgrid.gov)

While the benefits vary widely among circuits depending on a number of unique factors, strong double digit percentage improvement (i.e. reduction in SAIFI, MAIFI and SAIDI indices)[4] in the 20-40% range was seen in most cases.

Reported reductions in SAIFI are generally smaller than those in SAIDI. Automation has more impact on reducing the duration and extent of outages than on reducing the frequency of outage events, most of which are due to equipment failures, severe weather, animals, traffic accidents, etc. The reduction in SAIFI with SG-DA may be partly attributable to the minimum duration threshold for inclusion in the SAIFI index.

Some outages that were "sustained" (longer than five (5) minutes) and counted in SAIFI may be shortened by the use of automation to the point where they fall into the "momentary" bucket (shorter than five (5) minutes) and are therefore counted in MAIFI instead of SAIFI.

Also of note, the Customer Average Interruption Duration Index (CAIDI), which measures only the duration of outages for customers affected by an outage (rather than the average for all customers) often increased in the pilots. The DOE explanation is that because automation successfully insulates many customers from experiencing outages, those remaining customers who are affected will tend to be those that are more directly impacted and may require lengthy manual restoration efforts (and therefore contribute to longer average outage times).

This result is consistent with findings reported by Duke Energy Ohio[5] and indicates that, as a metric, CAIDI is not a useful measure of SG-DA effectiveness.

The DOE finds that the ARRA pilot funding targeted many utilities' worst performing circuits and these feeders correspondingly show strong benefits from automated switching. However, the utilities in the ARRA pilots also reported that centralized Distribution Management System (DMS) software was not yet fully operational to coordinate switching actions and that many utilities found the lead time and learning curve for full closed-loop automation implementation significant. Future reports may therefore show additional improvements in performance, as DMS deployments mature.

5.1.2 EPRI Smart Grid Demonstration Initiative

Another significant body of Smart Grid pilot experience is the set of 24 on-going utility programs included under the Electric Power Research Institute's (EPRI's) Smart Grid Demonstration Initiative

[4] System Average Interruption Frequency Index (SAIFI) measures the number of sustained outage events, lasting at least five minutes, experienced by the average customer on a utility system in a given year. Momentary Average Interruption Frequency Index (MAIFI) measures the number of interruption events shorter than five minutes. System Average Interruption Duration Index (SAIDI) measures the duration of sustained outages (minutes per year) experienced by the average customer. Customer Average Interruption Duration Index (CAIDI) measures the average duration of outage only for those customers affected by an outage during a given year. Expressions for SAIFI and SAIDI are given in Section 3.1.4

[5] As reported in the IEEE on-line ("Regulatory Update on Duke Energy", January 11, 2011) and confirmed by conversation with Lee Taylor, Duke Energy, Duke reached a stipulation with the Ohio PUC allowing an increase in CAIDI, in tandem with the decrease in SAIFI, as a result of its smart grid investments. The stipulation contained the following language: "No single customer will experience longer outage durations as a result of the increase in CAIDI in the context that such an increase is derived solely from Duke's implementation of Smart Grid and other distribution-related improvements, as described in its application and amended application."
The IEEE article adds that "To our knowledge, this is the first time that a regulatory opinion and order has asserted that an increase in CAIDI is not necessarily linked to longer outage durations."

(SGDI), which includes, in addition to US participants, utilities from Australia, Canada, France, Ireland and Japan. EPRI recently reported case studies from eight pilots in its five year program update.[6]

The overall SGDI encompasses a broad range of Smart Grid technologies, with a much stronger emphasis than in the US ARRA pilots on distributed energy resources, such as demand response and distributed generation. There are ten utility programs that include aspects of distribution automation and grid management software systems, including projects at eight US utilities (AEP, Con Ed, Duke, First Energy, HECO, KCP&L, SMUD and Southern Company) as well as Ergon of Australia and Hydro Quebec of Canada. As of mid-2013, most pilots had moved into the "data collection" and "analysis" phases, with completion expected by 2015.

None of the case studies reported in the five year update appears directly targeted at storm resiliency (the closest are the Hydro Quebec and Southern Company examples which address voltage control applications. There are no direct reports of reliability benefits, such as SAIDI/SAIFI reductions, or any anecdotal information with regard to storm resiliency applications.

Recommendation SG-1: Assess/deploy most impactful SG-DA technologies

***Mandate* that *EDCs assess impact of reliability-oriented SG-DA and create investment and deployment plans* for the most impactful technologies for their service territory.**

The benefits of SG-DA to system reliability are now documented, with examples emerging as a result of the ARRA stimulus funding and other efforts (see discussion in Section 5.1.1). A range of 20-40% SAIDI and SAIFI improvement appears to be achievable for many different circuits and locations.[7] The New Jersey EDCs should base their investment and deployment plans for reliability-oriented SG-DA on an impact assessment. This recommendation is discussed further in Section 6.4.

5.1.3 Resiliency versus Reliability

Major storm events – those that affect a large percentage of a utility's customers for an extended period of time – are intentionally excluded from the standard reliability metrics (SAIDI, SAIFI, MAIFI, CAIDI, etc.). While the exact definitions vary from state to state, "major events" are assumed to be relatively infrequent and beyond the utility's direct control. They are excluded from the reliability indices in order to avoid skewing the statistics – a single Irene or Sandy can cause as much outage downtime as a typical customer might experience in a decade of ordinary service. Many state regulators have therefore chosen to maintain a separate review process (such as the New Jersey Major Event Report filings discussed in Chapter 2) for events that meet the "major event" threshold.

Resiliency, the response of a utility system to major events, presents a different challenge for automated systems than that presented by day-to-day reliability. During the often chaotic initial response to a major event, while the storm is still raging with high winds and flood waters, there may be multiple crews in an area at the same time, limited communications to utility field assets and personnel, limited access to equipment (due to blocked roads or floodwaters), and lack of a

6 "EPRI Smart Grid Demonstration Initiative: 5 Year Update", Available from EPRI website, Matt Wakefield and Gale Horst, 2013.

7 Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results, US DOE, December, 2012 (available at smartgrid.gov). This range is also confirmed by GE's own analyses and conversations with several utility customers, such as Duke, AEP, and NSTAR.

complete damage assessment. Control room operators will have only limited visibility to real-time conditions in the field.

As a result, during the storm event itself, closed-loop automation is typically turned off to prevent accidental damage to utility equipment or personnel, as switches are reset and circuits re-energized.[8]

Only manual or supervisory actions are undertaken during this time (so called “human in the loop”) with the control room operators effecting control actions using the automation, but only in conjunction with contact to field personnel with line of sight to the asset.

Once the storm has subsided, communications have been re-established, and an initial damage assessment can be safely conducted, the automated systems are allowed to operate again, and there is strong reason to believe that SG-DA will be beneficial to the restoration effort. During the extended post-storm restoration period which may last days or weeks, SG-DA should allow utility operators to:

- Isolate the affected fault area to contain damage to equipment;
- Localize and limit affected customers;
- Restore service through alternate feed paths and more safely utilize distributed resources (e.g. mobile generators) where available;
- Confirm service restoration quickly;
- Detect nested faults downstream;
- Communicate and confirm instructions to field crews;
- Provide more accurate/detailed information to customers on restoration timing.

Because of the relatively infrequent nature of major events, and the lack of standard industry metrics for assessing their impacts, the resiliency benefits of SG-DA have not yet been fully measured and quantified. GE believes New Jersey has an opportunity to close this gap. While pursuing SG-DA investments that are economically justified on their reliability merits alone, New Jersey can also lay the groundwork for quantifying the additional benefits DA provides for resiliency during future storms.

Specifically, GE recommends that the BPU target a portion of SG-DA deployments to subsets of distribution circuits with high storm exposure. By tracking the performance of these circuits, alongside similarly-situated circuits that do not receive SG-DA investment, the BPU will be able to evaluate and quantify the resiliency improvements directly attributable to the automation).

[8] Conversation with GE experts and multiple utility customers. The specific concern with regard to communications availability during storms is also cited by Quanta: “Since Smart Grid technologies rely heavily upon communications systems, utilities wishing to use Smart Grid functionality during storm restoration will have to develop and coordinate a communications restoration plan along with its [sic] power restoration plan.” Cost Benefit Analysis of Utility Infrastructure Upgrades and Storm Hardening Programs, Richard Brown, 2009, p. 81

In the future, this should allow the New Jersey EDCs to identify those technologies and circuit attributes that have the greatest potential for resiliency benefit, and to fully incorporate these benefits into the business case for consideration of additional SG-DA investment. This discussion leads to the recommendations below:

Recommendation SG-2: Deploy SG-DA technology selectively for Resiliency

***Target deployment plans to evaluate SG-DA technology effectiveness* for resiliency by strategic deployment on subsets of circuits with similar storm exposure and physical attributes.**

Blue Sky reliability assessment methodologies exist, but major storm resiliency impact is harder to evaluate, since major storm events are rare and are excluded from the reliability indices. As EDCs submit deployment plans, the BPU can create selection criteria to target a subset of deployment to areas with high storm exposure in order to measure the reduction in restoration times compared to similar areas without such deployments. This recommendation and implementation steps to create selection criteria for targeted resiliency deployments are discussed further in Section 6.4.

Recommendation SG-3: Track and report SG-DA effectiveness during storms

Define and mandate reporting requirements to track effectiveness of SG-DA technologies in storm recovery activities.

Analytical models for projecting SG-DA "resiliency" impact and the associated cost/benefits do not presently exist. However, EDCs can collect actual/empirical information from future storm events in order to quantify the resiliency and storm recovery impact of implemented SG-DA on their system. These data can be used to assess additional SG-DA investments and target those investments towards the locations and types of circuits that will see the strongest storm resiliency benefits. This recommendation and proposed steps for tracking actual SG-DA impact on resiliency and storm recovery are discussed further in Section 6.4.

5.2 Synopsis of Industry SG- DA Practices and Trends

To satisfy the BPU scope, GE performed a literature review of publicly available documents related to the applications of Smart Grid (SG) and Distribution Automaton (DA) to emergency response and storm recovery by electric utilities.

The sources included news reports, academic studies, utility case studies, and reports by industry associations and national laboratories. Additionally documents from state public utility commissions or other state entities related to the deployment of SG and DA based approaches for emergency response and storm recovery were reviewed.

Due to limited public information available, rather than restrict the literature search to the Northeast *and mid-Atlantic region*, the literature search was extended to include several Southeastern areas prone to Atlantic storm damage (North Carolina and Florida), as well as a few inland states (Illinois, Michigan, Missouri) that also have significant winter storm exposure.

5.2.1 General SG and DA Technology Trends

Smart Grid (SG) investments typically serve many objectives for utilities and their customers, with the investment in technology justified on the basis of multiple predicted benefit streams. These benefits may in turn be allocated among different stakeholders – utilities, customers, shareholders, and society. For example, some SG investments, such as Advanced Metering Infrastructure (AMI), may yield lower costs for the utility (from avoided manual meter reading), and improvements in customer service, e.g. the ability to deliver new time-varying rates and better energy information to support customer choice. Other Smart Grid investments aim to improve system reliability with a customer benefit (reduced outage time), and may also lead to increased productivity and improved operational efficiencies for utility employees and assets. These utility benefits should ultimately benefit customers, at least to the extent they are passed on in lower rates as part of a future rate case.

While historically the focus of SG-DA technologies has been on modernizing the distribution system to improve efficiency, productivity and blue-sky reliability, there has been a recent shift toward evaluating and verifying the storm/resiliency benefits of SG-DA technologies.[9] There is a wide array of SG and DA technologies that have the potential to improve operational efficiency and reduce restoration costs during storm events.

The currently available solutions include applications inside the utility control room, out on the electric distribution system (from the distribution substation to the meter). For example, over the last couple of years, several state and federal projects have been investigating microgrids as a technology option to support grid resiliency.[10,11,12,13]

The long-term direction of the trend in SG-DA technologies is towards a much higher degree of “situational awareness” for the utility operator. The seamless integration and coordination of SG-DA applications enables movement of relevant information between the field, operations center, and back office in a time sensitive fashion. This allows the operations center to efficiently coordinate and schedule the activities and movement of restoration crews and assets, in response to a storm or other emergency event.

5.2.2 Summary of Key Findings by Technology

This section summarizes the key findings from publicly available literature for each technology area, and places these in the context of the BPU’s objectives for storm resiliency. The discussion includes both the application of existing technologies, as well as new or emerging applications and trends that intersect with the Smart Grid domain. For a more thorough discussion of the findings for each individual technology area, please see Appendix C: SG and DA Technologies and Programs.

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[9] “RESILIENCY: How Superstorm Sandy Changed America’s Grid”, Greentech Media, Stephen Lacey, 2014 http://www.greentechmedia.com/articles/featured/resiliency-how-superstorm-sandy-changed-americas-grid

[10] “Microgrids: An Assessment of The Value, Opportunities and Barriers To Deployment in New York State”, NYSERDA, Final Report 10-35, September 2010. http://www.nyserda.ny.gov/-/media/Files/Publications/Research/Electic-Power-Delivery/microgrids-value-opportunities-barriers.pdf

[11] “SPIDERS: The Smart Power Infrastructure Demonstration for Energy Reliability and Security”, Sandia National Laboratories. http://energy.sandia.gov/wp/wp-content/gallery/uploads/SPIDERS_Fact_Sheet_2012-1431P.pdf

[12] “Microgrids in NYC & Conn.—A New Kind of Power Struggle”, Climate Central, Bobby Magill, September 10, 2013. http://www.climatecentral.org/news/microgrids-in-nyc-connecticut-a-new-kind-of-power-struggle-16451

[13] “Maryland Resiliency Through Microgrids Task Force Report”, 2014 http://energy.maryland.gov/documents/MarylandResiliencyThroughMicrogridsTaskForceReport_000.pdf

Distribution Automation

Reliability-oriented SG-DA, including automated field devices (switches, sensors, and reclosers) and decentralized or centralized control, improves reliability by accelerating the detection and isolation of faults and reconfiguring the system to restore service more quickly to more customers (wherever feasible). As discussed above in Section 5.1.3, this benefit is now well established for normal “blue sky” operations, with several examples in the literature of 20-40% reduction in the standard industry outage metrics, depending on circuit and system characteristics. Further evidence of the reliability benefit of distribution automation is presented in Section 5.4.

The precise benefits of DA to storm resiliency and recovery are harder to quantify (due to the lack of available methodologies and metrics) but anecdotal evidence suggests they are real and potentially substantial. While advanced automation systems may not be able to operate autonomously during a major event, due to the chaotic nature of utility storm operations, there is every reason to believe that SG-DA will be valuable to utility operators during extended storm recovery and restoration. For this reason, GE earlier presented Recommendation SG-1 (which is further discussed in Section 6.4.).

SG-1: Mandate that EDCs assess impact of reliability-oriented SG-DA and create investment and deployment plans for the most impactful technologies for their service territory.

Communications Technology

Robust, uninterrupted communications are vital to the storm restoration effort. Utility plans should address both internal communications (between control centers and field crews), as well as external communications with customers and other key stakeholders, and ensure redundancy and cybersecurity of critical communications infrastructure. A discussion of internal communications used during storm situations and a recommendation for hardening internal communications was presented earlier in Section 4.2.2.

An example of an emerging technology for internal communications is satellite or GPS tracking of field crews integrated with work management systems (WMS), which gives the utility operator real time situational awareness and allows efficient dispatching and rerouting of crews.

Mobile social media technology is increasingly becoming an important ingredient of utility external communications activities. During a storm, customers can receive and communicate important updates with the utility via smart phones when other, more traditional communications may be unavailable (because customers are displaced or landline service is disrupted). Section 3.1.1 discussed the use of mobile technology for outage reporting and communications during storms.

Monitoring, Sensing, and Control Technologies

Digital sensors and measurement devices, such as transformer monitors, remote fault sensors, and AMI Smart Meters all help to provide additional situational awareness to the utility operator. During storm operations and post-storm recovery, increased situational awareness provides faster detection of fault conditions to allow utility operators to respond more rapidly – both through automation and dispatch of field crews. D-SCADA and Integrated OMS/DMS14 are emerging

[14] Integrated outage management systems and distribution management systems combine the capabilities of both applications; another term for the same functionality is advanced DMS or ADMS.

technologies that provide the operator interface for monitoring remote sensors, as well as the control fabric for communication with switching devices on the distribution system.

Advanced Asset Management System (AMS) and Work Management System (WMS)

AMS and WMS technologies provide tracking of the availability of utility field crews and their operational assets (e.g., trucks and tools), ensuring that the right resources are available where and when they are needed.

Emerging technologies in this area that can be particularly beneficial for storm response include advanced Roster Management/Callout Processes for efficient crew mobilization; integration of WMS with AM/FM GIS to allow geographic location of assets (e.g., to identify location of the nearest spare part in inventory); and Automated Vehicle Location.

Geospatial (or Geographic) Information Systems (GIS)

GIS and mapping technologies play a role in each phase of storm prediction, response, and recovery. Emerging technology applications include the geo-tagging of hazards during the post-storm damage assessment and the integration of AMI and mobile data with GIS. An example is identification of a piece of damaged equipment from a customer report, using either a meter location and/or a smart phone photograph of the damage. As discussed in Section 3.1.1, all the New Jersey EDCs maintain social media accounts (mostly Facebook and Twitter) and provide at least one mechanism for customers to report outages and dangerous situations (via websites, mobile apps, SMS, etc.).

Storm Damage Prediction

Model-based storm damage prediction systems take weather tracking data and combine them with detailed electrical system data to create highly detailed and informative damage prediction models for different storm types. Accurate storm damage prediction allows for better storm planning. For example, utilities can allocate, pre-position and mobilize storm response resources in the right locations to respond to likely storm damage.

The findings in this area lead to the following recommendation to the BPU:

Recommendation SG-4: Require EDCs to evaluate damage prediction tools

Require EDCs to quantify potential improvement in damage forecasts using storm tracking and damage prediction tools, and assess resulting improvement in storm response.

As part of ERP, EDCs must discuss how to track, predict damage, and prepare for major storms. This recommendation takes it to a higher level based on data analytics and system simulation. If evaluation warrants eventual implementation, the advanced data analytics software will leverage the full range of historical and real time weather and utility data to perform analysis of circuit and equipment failure potential, anticipate number of outages, identify high likelihood locations, and determine crew requirements and full system restoration times. This recommendation along with possible implementation steps are discussed further in Section 6.4.

Distributed Energy Resources (DER) and Microgrid (MG) Applications

Traditional customer-owned back-up generation, often combined with storage, is used to provide redundancy to facilities with high reliability requirements, such as hospitals and data centers. Facilities with large thermal requirements can also sometimes justify distributed generation (DG) as part of a CHP (combined heat and power) solution. Utilities currently face regulatory and business model barriers that inhibit ownership and operation of DG on customer facilities.

Today's technology allows increasingly complicated and coordinated control of multiple DER (including customer demand response, storage, etc.) within a facility or among multiple adjacent facilities in close proximity. When multiple facilities or DER are connected behind a common point of control, and can operate in parallel or isolation from the larger grid, this arrangement is called a microgrid. DER and microgrids allow for higher levels of reliability and resiliency at a significant additional cost.

A number of state and federal policy makers are currently exploring the value of microgrids as a regional storm resiliency strategy, by targeting clusters of critical public facilities, such as hospitals, police, fire, prisons, wastewater treatment, and emergency evacuation shelters. The benefits of microgrid are extremely site dependent and require detailed technical/economic feasibility studies to determine their value. New Jersey is already taking steps to promote DG and CHP as a way to improve energy resilience in the 2011 New Jersey Energy Master Plan. As such, GE makes the following recommendation to the Board:

Recommendation SG-5: Assess the value and feasibility of DG and Microgrids

Continue to look at the value of microgrids and back-up generation to the state, consistent with the energy master plan, and initiate techno-economic feasibility studies where practical.

A primary objective of grid resiliency is to ensure uninterrupted operation of services needed during major storm events. Critical facilities require higher levels of resiliency. Back-up generators, and microgrids if warranted, can act as single controllable entities and operate in isolation from the grid when needed. Some Northeast states, such as New York, Massachusetts, Connecticut, (and even NJ through its Energy Resilience Bank), are exploring development of microgrids at critical locations to provide up to two weeks of uninterrupted power during major events. This recommendation is further discussed in Section 6.4.

Advanced Metering Infrastructure (AMI)

Deployments of AMI have proliferated in many parts of the US, with tens of millions of Smart Meters in operation. Among Eastern states, Florida, Georgia, Pennsylvania, Maryland, and DC have significant deployments. New Jersey has so far not followed this trend.

The primary drivers for AMI adoption include utility cost savings from avoided manual meter reading and provision of better customer energy information (for dynamic pricing and demand response). Though not necessarily a primary driver of adoption, AMI systems also help reliability. Many smart meters come with "last gasp" capability that can aid in outage notification and verification of service restoration, both of which are beneficial in storm response and recovery.

An emerging application is the integration of AMI data into OMS and DMS (sometimes referred to as Advanced DMS or ADMS) to provide greater situational awareness.

Demand Response (DR)

Many types of DR programs have been developed to curtail discretionary loads and manage peak demand. Some programs involve pricing incentives (interruptible rates, TOU/VPP/CPP/RTP, etc.), while others communicate directly to specially equipped end-use devices (IL, DLC, AC cycling, AutoDR). DR can benefit storm response by providing flexibility to reduce localized grid congestion during periods of physical constraint (i.e. inadequate supply available to serve demand within a section of the grid). However, physical curtailment is likely to be more effective in a storm context than price-based programs.

Grid Modernization Roadmap

A Smart Grid roadmap allows the evolution and coordinated deployment of multiple technologies over a period of many years. The roadmap should address the many inter-related aspects of this technology transformation, such as the communications architecture, data management, cyber security, etc.; as well as behavioral factors: process change management, employee training, and customer communications.

For storm resiliency applications, the roadmap will create a path towards deeper situational awareness for utility operators, integrating sources of data and control into a holistic view. This requires an evolutionary investment and development plan that starts with core infrastructure (communications platform), integrates individual hardware applications as they deploy (e.g. advanced sensors), migrates up through control room software and visualization (integrated DMS), and can eventually extend to include advanced data analytics, social media and mobile applications, and other future/emerging technologies not initially in scope.

5.3 Review of EDC Filings

This section reviews the EDC submissions related to SG and DA plans under items BPU63 and 65, and makes recommendations for improvement.

5.3.1 Overview of the Findings

In the wake of Hurricanes Irene (and subsequently Sandy), BPU orders 63 and 65 directed the EDCs to submit a summary of their current and planned Smart Grid (SG) and Distribution Automation (DA) activities. Specifically, BPU-65 ordered:[15]

> *"Each EDC shall file a Smart Grid - Distribution Automation Plan (SG-DAP) filing. The Smart Grid-Distribution Automation Plan shall include the development and implementation of feeder and substation automation as part of an overall Distribution Management System (DMS) and Outage Management System (OMS). The SG-DAP shall, including [sic] but not be limited to the following: Automatic circuit reclosers (ACR), automation sectionalizing and restoration (ASR), advanced voltage control, VARs control, network protection/monitoring/controls, remote terminal units, remote fault detection, smart relays, equipment health sensors, outage detection devices and smart meters.*

[15] BPU Docket No. EO11090543, Recommendations in the Board's Letter of January 23, 2013 (emphasis added)

> *The Smart Grid - Distribution Automation Plan Filing shall include the timeframe for the development of each component and the overall plan, as well as the costs and benefits of each individual component and the entire plan to the EDC and the ratepayer.*
>
> *The Smart Grid - Distribution Automation Plan shall be developed with the goal to implement a more resilient and "self-healing" distribution grid and with the objective to improve the distribution system reliability and optimize the distribution grid operation overall with a specific focus during and after a storm events [sic] such as Irene".*

GE has conducted a thorough review of the EDC filings submitted in response to the BPU's orders 63 and 65. While the individual responses vary in quality and completeness, on the whole, the information presented is inconsistent across EDCs, and does not provide sufficient insight to enable definitive assessment of the EDC plans or make recommendations with regard to any specific plan. Required information in the order on "*the timeframe for the development of each component and the overall plan, as well as the costs and benefits of each individual component and the entire plan to the EDC and to the ratepayer*" is incomplete and lacking the requisite data and analysis.. The EDCs response to the request for deployment timeframes and costs for their SG-DA investments also varied in quality and completeness. ACE, for example, provides a summary table of each of its SG-DA programs, with a deployment time frame and approximate cost for the period 2013-2015.[16] None of the submissions attempted to segregate the costs between the EDC and the ratepayer.

Benefits information was even more lacking. The EDCs failed to provide information on the benefits of their investments in SG-DA that was sufficiently detailed enough to be verified through independent analysis. What information is provided is largely anecdotal and unsubstantiated. The following list of examples is illustrative:

- ACE cites a "potential "20 to 50% improvement in feeder reliability" based on parent PHI's experience of a 22% reliability improvement in a 2008 DA pilot.[17] While this wide range of improvement in reliability metrics is consistent with other industry experience[18,] there is no further description of how the PHI pilot might correlate with ACE's own extensive portfolio of SG-DA investments in New Jersey. Are the same technologies being deployed in similar applications on similar types of circuits? How do the improvements vary by circuit type?
- JCP&L describes its "…evolving DMS comprised of several system components that uses DA applications in its operations", as well as "26 DA schemes" connected through SCADA.[19] Neither of these investments is described in sufficient detail to understand what technologies are being used, where and how they are being deployed, or with what expected benefits (i.e. reliability, system efficiency, productivity, etc.).
- PSE&G provides a hypothetical example to illustrate the benefits of its auto-recloser investments. By installing two additional feeder reclosers within a section of 13kV loop network serving 1000 customers, PSE&G predicts a 33% reduction in customers affected by an outage.[20] Other than via reference to Energy Strong, however, there is no further discussion of

[16] ACE BPU-65, page 16-17
[17] ACE BPU-63, page 6-7 and ACE BPU-65, p. 8 (with supporting figures on page 9)
[18] See Section 5.1
[19] JCP&LBPU-65, page 1-2
[20] PSEG BPU-65, page 4

how many of PSE&G's circuits this approach applies to, how many preventable outages occur in a given period or the potential value to ratepayers for the reduction in outage events attributable to PSE&G's investment in automatic reclosers on its loop network.

- An even broader claim is made by PSE&G that had the technologies proposed in its Energy Strong filing been available during Sandy, "*PSE&G estimates that customers on average would have seen approximately an 8% reduction in outage time experienced*."[21] The basis for this statement is nowhere provided or elaborated upon.[22]
- RECO provides an estimate of the fast response to a fault with its SCADA-driven Integrated System Model (15 seconds from fault detection to command execution).[23] While such speeds are commonly achievable with automated systems,[24] RECO's claims are impossible to validate without reference to the specific events, command and control architecture, and real world experience of operating these programs. Furthermore, no attempt is made to translate the technical capability of the automation into an EDC or ratepayer benefit.

Recommendation SG-6: Mandate standard EDC SGDAP reporting

Mandate <u>enhanced EDC SGDAP submissions</u> to ensure completeness, and to enable comparative evaluation and benchmarking of SG-DA investment plans.

Based on the observations above, GE recommends that the BPU adopt a consistent reporting framework for the New Jersey EDCs that would allow for comparative evaluation and benchmarking, both across the EDCS and with other utilities outside New Jersey. The reporting framework would include requirements for the report narrative, as well as a questionnaire or reporting checklist of required data elements for each SG-DA project or technology element. This recommendation is discussed further in Section 6.4.

5.3.2 Detailed Comments on EDC Filings for Compliance with BPU-63 and 65

This section presents an in-depth review of the SGDAP filing for each of the New Jersey EDCs. A review framework is presented to compare and contrast the *completeness* of the plans against the requirements set out in the order, and then each EDC filing is individually discussed.

<u>Review Framework</u>

Table 5-1 and Table 5-2 below provide an overview of GE's detailed review of the EDC filings against the technology elements specifically requested by the BPU in its instructions mandating the 63 and 65 filings. For purposes of organization, we have divided the DA technology spectrum into four conceptual categories based on the time horizon in which action is taken: Prevent, Predict, Restore, and Manage. These broad headings should be understood only as an approximate guide to DA system behavior. Of course, there are overlapping functions and technologies which can aid in multiple time domains.

[21] PSEG BPU-65, page 5
[22] RECO BPU-65, page 6
[23] RECO BPU-65, page 6
[24] Based on GE's expertise and experience

The tables attempt to answer the question: "Did the EDCs address each technology element as required in the BPU's directive?"[25] This qualitative evaluation illustrates the degree to which each EDC's filing addresses each element (more or less completely). Where more detail is provided on a given technology, we infer that there is likely a stronger, more extensive underlying program of pilot activity.

Where little or no detail is provided, it is not necessarily the case that no program exists. We are unable to distinguish between the absence of activity and reporting omissions. Moreover, the ratings are subjective and should not be taken as a scoring of the quality or value of the EDCs program towards meeting the BPU's objectives, which we were not able to evaluate. As explained above, information necessary to provide an objective benchmarking and scoring of each EDC's SG-DA plan, for example clear and consistent information about the expected benefits of SG-DA investments, was not included.[26]

Overall, GE draws the following directional inferences from the relative weight and completeness of the information the EDCs have chosen to provide:

- Descriptions of pilots and plans in the "Prevent" and "Manage" categories were relatively incomplete (with the exception of ACE's equipment health monitoring and Volt-VAr control activities, which are described with reasonable completeness). We take this to mean that the EDCs have fewer pilot activities and plans in these technology domains.
- In the "Predict" domain, the completeness and depth of responses varied. ACE, for example, provided extensive information about its Advanced SCADA and Advanced Communications deployments. PSE&G's filing also appeared "complete" or "mostly complete" in several technology areas. JCP&L and RECO's filings provided less information.
- The EDC responses were generally most complete in the technology elements we have labeled "Restore", that is, Smart Relays, Automatic Circuit Reclosers, and Automatic Sectionalizing and Restoration equipment. This is consistent with the BPU's objectives in its 63 and 65 directives, as these are the technologies – automated field devices controlled through either centralized or decentralized intelligence – which GE contends are most directly linked to storm resiliency and response within the SG-DA spectrum.[27]
- Overall, the response provided by ACE covered more technology elements in more depth and may be deemed closest in spirit to compliance with the BPU's directive in orders 63 and 65. JCP&L, PSE&G, and RECO's responses were less complete with many of the required technology elements left unaddressed.[28]

In the following sections, we highlight specific examples of contents from the individual EDC filings that substantiate this directional perspective.

[25] BPU Docket No. EO11090543, Recommendations in the Board's Letter of January 23, 2013 (quoted above p.43).

[26] We were also not able to capture information that may be available to the BPU in other proceedings, such as PSE&G's "Energy Strong."

[27] See discussion in Section 5.1 and Recommendation SG-1.

[28] Again, we note that the PSEG has subsequently filed plans with the BPU related to its "Energy Strong" petition, which may remedy deficiencies in its 63 and 65 filings. GE did not have access to these documents in preparing its review.

Table 5-1 Overview of EDC Filings vs. Prevent and Predict Technology Elements

	Prevent		Predict					
	Network Monitoring	Equipment Health Sensors	Remote Fault Detection	Smart Meters	Advance d SCADA	Advanced Communica tions	OMS	DMS
ACE	Less Complete	Mostly Complete	Less Complete	Mostly Complete	Complete	Complete	Mostly Complete	Mostly Incomplete
JCP&L		Mostly Incomplete	Mostly Incomplete	Mostly Incomplete	Mostly Complete		Less Complete	Mostly Incomplete
PSEG	Less Complete		Less Complete	Mostly Complete		Mostly Complete	Less Complete	Complete
RECO	Less Complete	Less Complete	Mostly Complete	Mostly Complete		Mostly Complete		Mostly Complete

Complete	Mostly Complete	Less Complete	Mostly Incomplete	Incomplete	No Discussion

Table 5-2 Overview of EDC Filings vs. Restore and Manage Technology Elements

	Restore			Manage	
	Smart Relays	Automatic Circuit Reclosers	Automatic Sectionalizing and Restoration	Volt-VAR Control	Conservation Voltage Reduction
ACE	Complete	Complete	Complete	Mostly Complete	Less Complete
JCP&L	Mostly Complete	Mostly Complete	Mostly Incomplete	Mostly Incomplete	
PSEG	Complete	Complete	Complete	Less Complete	
RECO	Complete	Complete	Complete	Less Complete	

Complete	Mostly Complete	Less Complete	Mostly Incomplete	Incomplete	No Discussion

5.3.3 Atlantic City Electric (ACE)

ACE is a subsidiary of PEPCO Holdings, Inc. (PHI), a multi-state holding company which also operates utilities in DC, Maryland, and Delaware. ACE's filings contain both specific Smart Grid programs for its New Jersey territory and a summary of the broader corporate strategy and experience of its parent PHI.

Highlights of ACE's SG-DA Program

ACE has made a significant investment (with help from its Smart Grid Investment Grant award) in Automated Sectionalizing and Restoration (ASR) and has created an on-going investment plan, as follows:

- 27 feeders (at 8 substations) serving 54,000 customers were scheduled for installation by end of 2013, plus an additional 6 feeders (at 3 more substations) serving 10,500 customers in 2014.
- 19 more feeders were identified at the same substations, serving 29,000 additional customers that are slated for ASR next year.
- A "similar number" of feeders will be added each year thereafter until all targeted feeders are automated.
- In addition, between 60 to 80 Automatic Circuit Reclosers (ACRs) will be added each year.
- Substations are being equipped with smart relays at the substation feeder terminal.[29]

Overall, ACE's reliability-oriented SG-DA investment program appears aligned with the BPU's goal of improving resiliency and storm restoration. ACE cites parent PHI's experience of a 22% reliability improvement in a 2008 DA pilot.[29] Based on industry experience, we agree that ACE should see reductions in blue sky and storm restoration time on its automated circuits of between 20-40%.[30]

ACE confirms that its ASR will not be operated during major storm events.[31] Nevertheless, GE believes this program is likely to help in the post-storm recovery period in restoring service more quickly to more affected customers, limiting the extent of damage, and providing better visibility and information on restoration times to both ACE and its customers.[32]

Other ACE Smart Grid Initiatives

Other ACE SG initiatives are likely to aid ordinary reliability, though they are not directly targeted to storm resiliency. These include:

- Capacitor Bank Automation and transformer DGA programs. These equipment health monitoring investments are good preventive "hygiene" that will reduce equipment related faults and aid in the early detection of pre-failure warning signals.
- Direct Load Control is a peak demand management technology that can also reduce overloading and accelerated aging of transformers and other equipment that occurs during system peaks.

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[29] ACE BPU-63, page 7 and ACE BPU-65, page 8
[30] See discussion in Section 5.1 and Recommendation SG-1
[31] ACE BPU-65, page 8;
[32] See discussion in Section 5.2 above

- ACE's investments in advanced communications (wireless mesh with fiber/micro-wave backbone) will be broadly shared across several technologies (including any future AMI), with likely benefits for future advanced DA applications.

PHI's Corporate Smart Grid Strategy

ACE's parent PHI has a long history with Smart Grid investments – dating back to before the Federal stimulus – and the corporate Smart Grid strategy included with ACE's filings is based on lessons learned in its other jurisdictions. Notably, PHI's other subsidiaries, PEPCO (serving DC and Maryland) and Delmarva Power & Light (in Delaware and peninsular Maryland) both have AMI programs, and PHI expresses hope that ACE will be allowed to follow suit at some future date.[33]

In the context of storm resiliency, an AMI with "last gasp" notification provides additional outage reporting and response benefits, as noted in Section 5.2 and Appendix C. The meter signal identifies fault locations more quickly (without relying on a customer to self-report an outage) and provides additional information to the OMS to help narrow down the fault location.

The AMI can also be used to send an outbound ping to a meter after repairs have been made upstream to confirm whether service is restored and detect any nested downstream conditions that still remain to be resolved while crews are still in the area (thereby reducing "truck roll" time and accelerating service restoration).

Both AMI with last gasp notification and the wider use of remote fault detection devices are cited as valuable technologies currently used in PHI's other jurisdictions, which have yet to be integrated into the strategy at ACE in NJ.[34] GE agrees that remote fault detection devices are important to storm resiliency. The last gasp capability in AMI meters, on the other hand, while useful in the context of storm resiliency, does not provide a stand-alone business case that GE believes would justify the entire AMI investment.[35]

Integration of DA with a central DMS is also cited as a future direction for PHI.[36] GE believes this is consistent with general trends in the industry – as utilities undertake more and more complex automation schemes, the use of centralized DMS software to monitor different DA inputs, execute complex algorithms for automated control actions, and provide higher level operator "situational awareness" including other management features, such as "what if" scenario modeling capability, is increasingly becoming a system requirement. GE notes that the industry is moving beyond traditional stand-alone DMS toward adoption of "Advanced" or Integrated DMS, which combines the capabilities of OMS (and the integration of AMI data into outage modeling) with the automated monitoring and control of DMS. These technology trends are discussed further in Section 5.2 and Appendix C.

ACE's filings do not provide sufficient information about its New Jersey operations to judge the specific cost-benefit merits of adopting individual technology proposals within PHI's corporate strategy.

[33] Per ACE BPU-65, p. 20, ACE proposed a Blueprint for the Future in 2007 which included an AMI similar to that deployed in PHI's other jurisdictions.
[34] ACE BPU-65, p. 18
[35] Based on GE's expertise and experience with AMI business case, reliability benefits are not the predominant driver for AMI investment.
[36] ACE BPU-65, pp. 18-19

5.3.4 Jersey Central Power and Light (JCP&L)

JCP&L's BPU-63 and 65 filings are the least extensive of the four EDCs (at two (2) and ten (10) pages long, respectively) and do not provide sufficient detail for GE to evaluate its current SG-DA program and its alignment with the BPU's storm resiliency objectives.

Current deployments are for "proven DA technologies" and are limited to:

- 100 programmable reclosers at targeted substations;
- Tie-reclosers at new substations (and selected existing circuits);
- Adaptive relaying (to allow remote switching to "fuse saving" mode during storms) for an 10 additional substations during 2013-2015[37].

These three technology elements appear related to storm resiliency. However, no further information is provided to help substantiate the business case or likely benefits for JCP&L or its ratepayers. With regard to targeting its recloser investments, JCP&L states that it is,

> *"currently working through the process of selecting the highest value locations that will provide the greatest reliability benefit."*[38]

Other SG-DA technologies appear to be in "wait and see" mode[39] and are referenced only in a bullet point list of parent First Energy's programs in its Ohio and Pennsylvania subsidiaries.[40]

5.3.5 Public Service Electric and Gas Company (PSE&G)

As a comprehensive Smart Grid - Distribution Automation (SG-DA) plan, PSE&G's BPU-63 and BPU-65 submissions were not sufficiently specific. It appears that at the time of these submissions, the Smart Grid initiatives at PSE&G were either being evaluated or deployed on a case by case basis. However, the submissions do refer to PSE&G's separate Energy Strong filing and GE is aware that the BPU has access to additional information on PSE&G's plans through Energy Strong.[41]

From a storm response standpoint, PSE&G's submissions focus primarily on circuit reconfiguration strategies. Other distribution automation initiatives included network monitoring, dynamic transformer monitoring and high speed communications. Two major subprograms were reported: Contingency Reconfiguration Strategies and Advanced technologies.

Contingency Reconfiguration Strategies

PSE&G's major contingency reconfiguration strategy relies on self-healing circuit loops. PSE&G conducted several initiatives that resulted in deployment of advanced loop schemes. One of the network design measures was adding redundant sections in loop schemes. Overall, during outages this strategy reduces the number of affected consumers, by isolating the affected sections of the

[37] JCPL BPU-65, pp. 3-4
[38] JCPL BPU-65, Attachment A
[39] JCPL BPU-65, p.9: "In the meantime, JCP&L will continue to stay abreast of industry developments and the consideration of other potential technologies/applications, which includes some or all of those contained in the [BPU's] recommendation."
[40] JCPL BPU-65, p. 7
[41] GE did not have access to Energy Strong which was still under settlement negotiation at the time of this review

network. The hypothetical example given in the BPU-65 filing states that by adding two additional reclosers, the proposed solution would result in a 33% reduction in the number of customers experiencing outages.[42] Although unsupported, this number is within the range of both industry experience and GE's experience of reliability-oriented DA schemes.[43]

PSE&G's plan is to improve loop designs with the installation of several smart devices, such as relays and reclosers. No details on the estimated number of additional devices were given, but due to the high costs PSE&G anticipates gradually adding more smart devices as its fiber optic communication infrastructure extends.

The installation of microprocessor-based devices at all substations and switching devices (switches, reclosers, sectionalizers) and their connection to SCADA provides the remote Set Up For Work feature, which has to be applied before overhead line crews can start the field work. This feature reduces restoration times during a weather event. For instance, in the case where only a substation is connected to the SCADA system, a typical value for the total duration of crew travel, inspection, isolation and restoration processes would be two (2) hours. If switching devices are also connected, an estimate for this duration would be only one (1) hour.[44]

Overall, PSE&G estimates that it will take at least five (5) years to implement the proposed reconfiguration strategy. It also stated that the program will result in an of average 8% reduction in outage time even for major storms like Hurricane Sandy.[45] No basis is provided to substantiate this claim.

Advanced technologies

In this category PSE&G focuses on monitoring, visibility and communications initiatives.

PSE&G proposed to install microprocessor-based relays and other smart devices on all distribution circuits. For instance, in addition to high-speed communications and smart sensors, PSE&G's monitoring systems that manage underground equipment include microprocessor-based protection. Besides enabling condition-based maintenance and remote control in storm incidents, this helps both to provide rapid restoration and to improve crew safety.

All of PSE&G's 26-kV networks already have the network monitoring systems installed. Although installation of microprocessor-based relays will enable fast diagnosis of circuit conditions, special design and construction measures are needed to secure these sensitive devices during severe weather events.

At the time of the BPU-65 submission, half of all PSE&G's substations (i.e. about 100 substations) had full SCADA capability. PSE&G has committed to equipping the remaining substations at the rate of 10 substations per year. The filings proposed the development of an Advanced Distribution Management System (ADMS). The main improvement of the ADMS over the DMS comes from additional data sources for outage information. Other than listing monitoring and rapid diagnosis, the filings did not specify what technologies would be beneficial for storm resiliency.

[42] PSE&G BPU-65, p. 4
[43] See discussion in Sections 5.1 and 5.4.
[44] Based on GE's expertise and experience
[45] PSE&G BPU-65, p. 5

In addition to the fiber optic communication network currently deployed on three sub-transmission circuits, PSE&G plans to extend this network much further into its distribution system.

The goal is to completely reduce the reliance on external communication providers. PSE&G estimates that it will take ten (10) years to fully implement this.[46]

In the area of asset management, PSE&G is primarily investing in dynamic transformer monitoring. The extensive measurements and transformer modeling techniques provide pre-failure indicators and facilitate condition-based preventive maintenance. PSE&G is committed to monitoring all future transmission-class and many medium-voltage transformers. Since transformer failures are primarily due to the age and loading of the asset, rather than storm events, PSE&G's asset monitoring strategy is likely to benefit ordinary reliability, but is not specifically targeted to storm resiliency.

5.3.6 Rockland Electric Company (RECO)

The BPU-63 and BPU-65 filings submitted by RECO are organized into sections that explain infrastructure improvements in the distribution network, substations, communications and cyber security. Several smart grid pilot projects funded by the Department of Energy (DOE) Smart Grid Investment Grant (SGIG) are discussed in detail together with the related operating benefits. Regarding the benefits for storm resiliency, the filings focus primarily on the introduction of circuit restoration technologies, fault-tolerant communications and advanced software, each of which is explained further in the following subsections.

Automatic Restoration and Circuit Reconfiguration

According to the fillings, RECO is in the process of automating a significant number of its circuits. For instance, mid-point reclosers are being deployed to provide automatic sectionalizing in the event of a fault. The auto-loops are designed with pairs of circuits and tie reclosers to automatically sense the outage on one circuit and restore power from the other circuit. Further reconfiguration will be enabled centrally with remote supervisory control achieved through RECO's Integrated System Model software (see the discussion below).

The pilot circuits have already been deployed in auto-loop configurations and demonstrated with the automatic fault clearing feature. There are now several distribution circuits in RECO's area that are fully equipped with distribution automation equipment. For instance, by placing SCADA controlled switches at segments along the main line each consisting of 250 customers, the quick detection and isolation of mainline faults is enabled. This allows for an outage to affect only a smaller number of customers, at most 250, since the two neighboring switches can isolate the fault to reduce the affected area.

[46] GE does not have a consolidated view on the question of SG-DA communications architecture. There are a number of c communication approaches including fiber, satellite, WiMAX, BPL, 3G and 4G cellular, which should be used individually or in combination, depending on network availability, cost, and other system requirements.

The RECO BPU-65 filing states that equipment control logic has already been employed for fast fault clearing and the automatic operation of the loop system. About 30 circuits are listed with mid-point reclosers, 30 circuits with automatic loop schemes and 10 circuits with both operator and smart loop schemes.

Advanced Software

The software infrastructure being implemented at RECO, i.e., the Integrated System Model (ISM), is a variant of the Distribution Management System (DMS). It is linked with other software subsystems such as Work Management System (WMS), Customer Information System (CIS), Geographic Information System (GIS) and Outage Management System (OMS). It is used both for planning purposes and in real-time operations such as restoration. At the time of submission, RECO was already on the path of deploying the ISM, since the restoration logic had already been developed.

The ISM is a model-centric control system. The model is built in real time using the data collected from substation breakers and other distribution automation devices using SCADA. The power flow engine runs in the background every time there is a significant change in input sensor or command data. The circuit topology changes are similarly updated in real time. The optimal power flow is then computed by ISM and control actions are automatically executed through the interconnection to the SCADA system.

Although ISM allows for a full coordination of the components of the distribution network and can be used to meet different utility objectives, it comes with a considerable integration burden and financial investment.[47]

The benefits of ISM in outages and storm conditions stem from faster response to changing conditions and other contingencies, as compared to current practice. It replaces or relieves the work of a distribution operator and results in optimal actions, thus speeding up the restoration process. The RECO filing asserts that for a fault isolation and restoration action, it will take under 15 seconds from fault detection to the command execution through SCADA. As discussed earlier, such speeds are commonly achievable with automated systems,[48] however, RECO's claims are impossible to validate without reference to the specific events, command and control architecture, and real world experience of operating these programs.

RECO plans to include the ability to enable storm damage prediction and resource optimization. This will be achieved by weather forecasts being overlaid onto the ISM. The filings do not mention the stage of development of this aspect of the ISM. At the time of the BPU-65 filing, various circuit devices had been added to the ISM. The model centric control system for both the restoration/reconfiguration and the volt/VAr optimization was expected to be placed in service by the third or fourth quarter of 2013.

Other Distribution Automation Initiatives

In the area of communications, RECO plans to fully equip some of the substations with time-synchronized, micro-processor based relays and fiber optic communications. In fact, high-speed optical rings will connect substations whereas most of the RTUs will use radio communications.

[47] RECO's BPU-63 and 65 filings are silent on these integration costs. .
[48] Based on GE's expertise and experience

With respect to resiliency, RECO has plans to upgrade several substations to become major communication hubs. On the way to or from central utility computers, sensor and control data can be routed through any substation that serves as a communication hub. Thus, in the event of equipment failure this solution may provide alternative communication paths and greater resiliency.

RECO's filings include a proposal for advanced SCADA system functionality. For instance, the alarm filtering feature that discards unnecessary alarms will be implemented, so that distribution operators get only the data they need in an easy-to-understand way.

For network monitoring RECO focused on transformer load monitoring. This enables transformer management with an objective to minimize transformer maintenance expenses. Similarly, breaker diagnostic equipment, i.e. breaker health sensors, will improve the reliability of the network by detecting potential future faults. Neither of these investments is directly aimed at storm resiliency.

The Integrated System Model discussed above will also serve for voltage and reactive power optimization. This model-centric solution to volt-VAr control will be used primarily to reduce energy consumption through dynamic adaptation of voltage levels but also to minimize electrical losses. At the time of filing the volt-VAr control system had been designed and was being tested on a simulator.

RECO's filings do not mention any plans for Advanced Metering Infrastructure (AMI).

5.4 Reliability/Resiliency and Economic Impact Analysis

The task plan from the BPU stated the following as one of the major tasks:[49]

> *"In addition GE shall evaluate the impacts of changes in technology such as the use of advanced meters and the implementation of smart grid/distribution automation would have on the resiliency of the electric distribution system and on the reliability of the EDC's service following a natural disaster such as a hurricane, Derecho, or northeaster. This evaluation shall include the cost to the EDC's of implementing the integration of that technology including advanced meters for improved resiliency and reliability throughout the State of New Jersey."*

This section discusses several methodologies for evaluating the impact of SG-DA technology on reliability and, by extension, resiliency by presenting results from publicly available studies, as well as GE internal studies.

5.4.1 SG and DA Cost-Benefit Analysis

The GE team reviewed available literature on estimating the reliability and resiliency impact and the costs and benefits of various SG and DA technologies. However, none of the currently available methodologies appear to provide estimates with any degree of accuracy.

In fact, according to the EPRI/NYSGCC study, R&D on Cost and Benefit Analysis Methodology, *"a consistent effective approach for determining the costs and benefits of new technologies and applications" should have the highest priority for New York utilities*. Each utility in the state currently

[49] New Jersey Board of Public Utilities Consultant Tasking Document, *Smart Grid (SG) And Distribution Automation (DA) Review, Analysis and Recommendations*, Dated December 3, 2013, Submitted to GE on February 13, 2014

has its own approach for assessing costs and benefits, which prevents *"comparison of studies that various companies conduct."*[50]

The comprehensive study by Quanta Technologies that examined the costs, utility benefits, and societal benefits for a variety of storm hardening programs in Texas, did not consider cost/benefits of "Smart Grid Technologies" for either transmission or distribution.[51] However, the study evaluated the "Societal Hurricane Benefits" of various smart grid technologies, assuming the technologies are deployed fully along the entire Texas coastline, and are integrated into a comprehensive Smart Grid system. Societal Benefits are calculated based on estimated reduction of total annual Societal Costs of storm damage in Texas. The results are shown in Table 5-3 below.

Hurricane categories are defined based on the maximum 1-minute sustained wind speeds according to the Saffir-Simpson Hurricane Scale[52]. Category 1 (lowest) is a "very dangerous wind" at 74 to 95 mph. Category 5 (highest) at 157 mph or higher, would result in catastrophic damage.

Since the Societal Benefits estimated in the above table are based on avoided hurricane costs in Texas, they should not be applied to other regions. However, the "percent reduction in restoration time estimates" provides a view of the reliability/resiliency impact of various categories of SG-DA technologies. For instance, the above results give a comparative view of the effectiveness of various smart grid technologies under different hurricane categories.

For instance, societal benefits (i.e., reduction in restoration times) of "DA, DMS, FLISR, FCI, Fuse Saving, Feeder Load Balancing" technologies decrease at higher hurricane categories, whereas the societal benefits of "20% DG penetration" increase at higher hurricane categories.

If a dollar value for customer interruption costs can be assigned to long outage intervals under various hurricane categories in New Jersey, then the societal benefits of listed smart grid technologies, assuming they are deployed across all of New Jersey, can be estimated. However, such rough estimates can only be indicative and very inaccurate.

The following subsections present the findings of the GE team's investigation on impact and cost-benefit analysis, and describe relevant experience and studies performed by GE that form the basis of Recommendation SG-1 (see Section 6.4).

[50] "Powering New York State's Future Electricity Delivery System: Grid Modernization, "prepared by the New York State Smart Grid Consortium, January 2013, Page 9, http://nyssmartgrid.com/wpcontent/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

[51] "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs", Prepared by Quanta Technology for the Public Utility Commission of Texas, March 4, 2009, Page 8, bottom of Table A.

[52] "Saffir-Simpson Hurricane Wind Scale", National Weather Service, National Hurricane Center, National Oceanic and Atmospheric Agency Website. http://www.nhc.noaa.gov/aboutsshws.php

Table 5-3 Hurricane Benefits of Smart Grid Technologies in Texas

	Hurricane Category 1	2	3	4	5	Total
	Reduction in restoration time					
PMU	0.5%	0.5%	0.5%	0.5%	0.5%	
Automatic Fault Location	1.0%	1.0%	1.0%	1.0%	1.0%	
DA, DMS, FLISR, FCI, Fuse Saving, Feeder Load Balancing	15.0%	13.0%	11.0%	9.0%	7.0%	
AMI System	10.0%	8.0%	6.0%	4.0%	2.0%	
20% DG penetration	10.0%	12.0%	14.0%	16.0%	18.0%	
GPS, MDT, Advanced Logistics & Work Scheduling System	5.0%	5.0%	5.0%	5.0%	5.0%	
Total lost GDP ($M/yr)	75.11	29.50	13.15	3.65	0.66	122.08
	Societal Benefits ($ millions per year)					
PMU	0.376	0.148	0.066	0.018	0.003	0.61
Automatic Fault Location	0.751	0.295	0.132	0.036	0.007	1.22
Total for Transmission Technologies						**1.83**
DA, DMS, FLISR, FCI, Fuse Saving, Feeder Load Balancing	11.267	3.835	1.447	0.328	0.046	16.92
AMI System	7.511	2.360	0.789	0.146	0.013	10.82
20% DG penetration	7.511	3.540	1.841	0.584	0.119	13.60
GPS, MDT, Advanced Logistics & Work Scheduling System	3.756	1.475	0.658	0.182	0.033	6.10
Total for Distribution Technologies						**47.44**

Source: "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs", Prepared by Quanta Technology for the Public Utility Commission of Texas, March 4, 2009, Page 76, bottom of Table 6-1. Reprinted with permission.

5.4.2 Research on Value of Reliability

There is a large amount of literature on the subject of the customer value of reliability and the damage caused by outages of different types and duration. Self-reported values from customer surveys can vary quite widely. A broad review of this literature was conducted by Lawrence Berkeley National Laboratories (LBNL) under a DOE-funded study.[53] In this work, the authors examine the range of reliability values in dollars per event, per kWh, and per kW, for different customer classes, for service interruptions of different durations, ranging from momentary (less than 5 minutes) up to 8 hours, and derive mean values from regression analysis of the available data. An example of the results is provided below by way of illustration in Table 5-4.

As can be seen, for each category of customer, the damage caused by outages of longer durations can be an order of magnitude higher than that caused by momentary interruptions. In addition, medium and large commercial and industrial (C&I) customers[54] incur significantly more cost per

[53] LBNL 2132E, "Estimated Value of Service Reliability for Electric Utility Customers in the United States", Michael J. Sullivan, Matthew Mercurio, Josh Schellenberg, June 2009.

[54] LBNL defined Medium and Large based on customers using greater than 50,000 kWh per year.

event than small C&I and residential customers, due to the greater loss of economic activity and productivity entailed.

Table 5-4 Customer Interruption Costs (DOE/LBNL)

Interruption Duration					
Interruption Cost	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558.00	$9,217.00	$12,487.00	$42,506.00	$69,284.00
Cost Per Average kW	$8.00	$11.30	$15.30	$52.10	$85.00
Cost Per Un-served kWh	$96.50	$22.60	$15.30	$13.00	$10.60
Cost Per Annual kWh	$0.000918	$0.00129	$0.00175	$0.00595	$0.00970
Small C&I					
Cost Per Event	$293.00	$435.00	$619.00	$2,623.00	$5,195.00
Cost Per Average kW	$133.70	$198.10	$282.00	$1,195.80	$2,368.60
Cost Per Un-served kWh	$1,604.10	$396.30	$282.00	$298.90	$296.10
Cost Per Annual kWh	$0.0125	$0.0226	$0.0322	$0.14	$0.27
Residential					
Cost Per Event	$2.10	$2.70	$3.30	$7.40	$10.60
Cost Per Average kW	$1.40	$1.80	$2.20	$4.90	$6.90
Cost Per Un-served kWh	$16.80	$3.50	$2.20	$1.20	$0.90
Cost Per Annual kWh	$0.000160	$0.000201	$0.000246	$0.000558	$0.000792

A different approach to addressing the customer value of interruptions has been developed and is utilized by Duke Energy in its Ohio service territory. Duke has pre-determined and agreed with its regulator on a dollar value it should spend per outage avoided. This value for Duke Ohio, is $50 on a capital cost basis or $75 in Net Present Value basis.[55] In proposing specific reliability improvement projects, Duke refers to this value and seeks projects where the reliability value (reduced probability of outage times the number of customers impacted) can be achieved for less than this threshold cost.

Notably, Duke converts the actual number of customers on a circuit to a "Customer Equivalent (CE)", using a scaling factor of one "CE" for each 5 kW of peak load (i.e., a typical residential customer size). Thus, a 1 MW industrial customer will carry 200 times the weight of a residential customer in determining the value of reliability improvement on a given circuit.[56]

$$\textit{Duke Ohio Reliability Value} = CE \times P \times \$50$$

where

[55] Duke reports that actual spending per customer outage avoided in the industry varies from $25-300.

[56] Lee Taylor, Duke Energy, "*The Value of Customer Reliability to the Utility*," Presentation to the SEE Power and Reliability Committee, September 2012.

CE = Customer Equivalents

and

P = Probability of Outage Equivalent per year.

5.4.3 GE Studies on Cost-Benefit Analysis of SG-DA Investment

Beginning in 2006, before the federal stimulus, GE began conducting a series of studies with utility customers, including OG&E[57], PEPCO[58], and PacifiCorp[59], to evaluate the costs and benefits of different levels of SG-DA investment.

In each case, the methodology used looks at incremental investments and estimates the reduction in Customer Minutes of Interruption (CMI) using a set of system averages. Discreet cases look at higher levels of automation, with a steady decrease in CMI at each incremental step.

For higher levels of automation (OG&E Case 5, PEPCO Case 7), there appears to be a large jump in costs, as the requirements for automation move from decentralized field devices (switches, reclosers) to a centralized, software based scheme, operating in closed loop control mode with high speed, two way communications. Naturally, the investment case on a per CMI-avoided basis falls off sharply at this point, as the costs per circuit or per customer increase faster than the benefits.

Although the methodology employed to calculate benefits did not allow for targeting based on individual circuit criteria, some attempt was made to target the investment plan. For example, at OG&E it was observed that the 200 worst performing circuits (23% of the total) accounted for 71% of all outage minutes. It was therefore recommended to begin by prioritizing these circuits for higher levels of automation.

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[57] C. Killian and B. Flynn, "*Justifying Distribution Automation at OG&E*," DistribuTech 2009

[58] R. Stewart and B. Flynn, "*Modeling DA Improvements to Reliability Performance Metrics*," Western Power Delivery Automation Conference 2007

[59] B. Flynn and S. Lathrop, "*Distribution Feeder Automation Pilot at PacifiCorp*," Western Energy Institute Conf. 2006

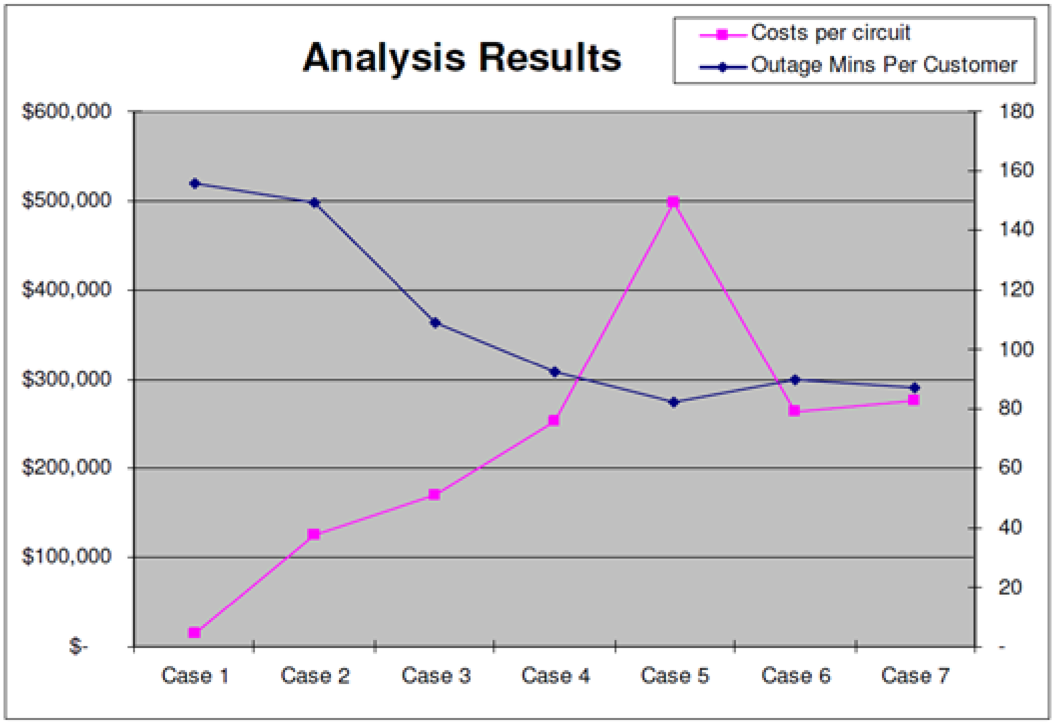

Figure 5-3 Sample Results from OG&E DA Business Case

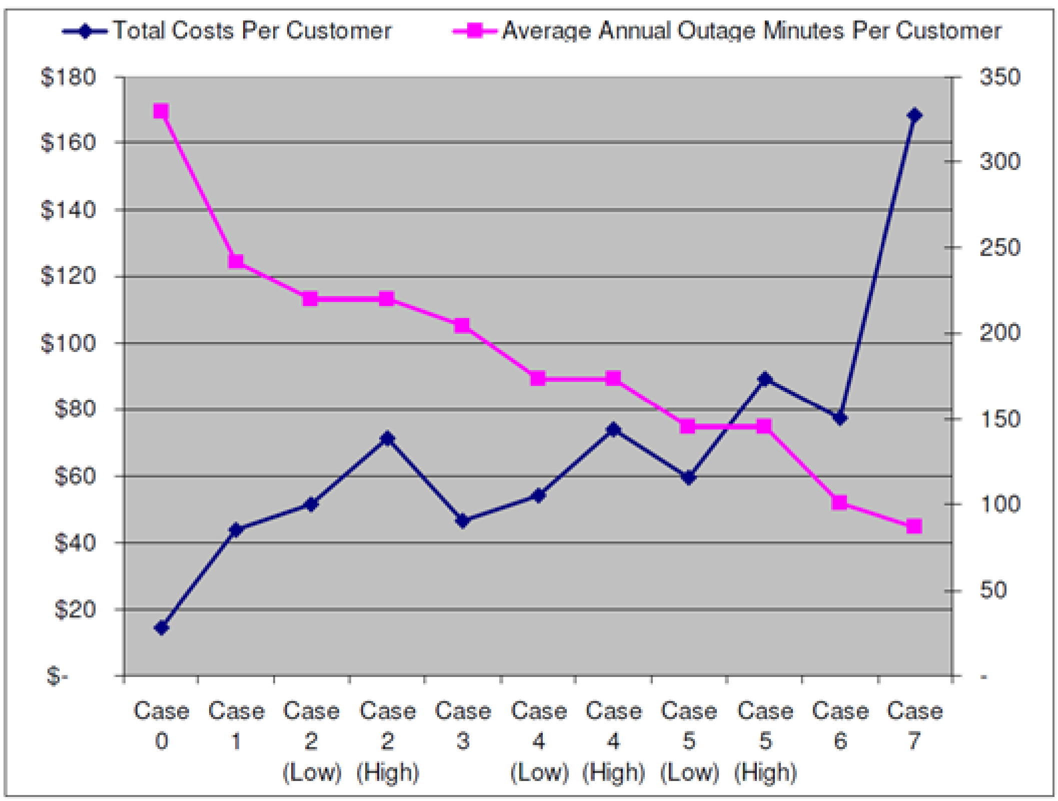

Figure 5-4 Sample Results of PEPCO DA Business Case

5.4.4 GE Work on Circuit Simulation

Beginning in 2013, GE Energy Consulting has conducted a series of SG-DA cost-benefit analyses using commercial distribution simulation modeling software used by many utilities in the US.[60] The approach began with a group of 16 actual distribution feeder models, obtained from two utilities, which represented a range of different topologies and customer load density characteristics (e.g. rural feeders with fewer customers per line mile, urban feeders with high concentrations of load, suburban feeders with heavy commercial and industrial loads, etc.).[61]

Using these different circuit models as prototypes, a set of DA investment scenarios were developed and evaluated to simulate the benefit in terms of predicted outage reduction with increasing levels of DA investment. A set of scenarios were created to be representative of different investment paths, including combinations of both automated field devices (sensors, switches, and reclosers) and software (OMS, DMS in "monitoring only" mode, DMS in "full automation" mode, etc.).[62]

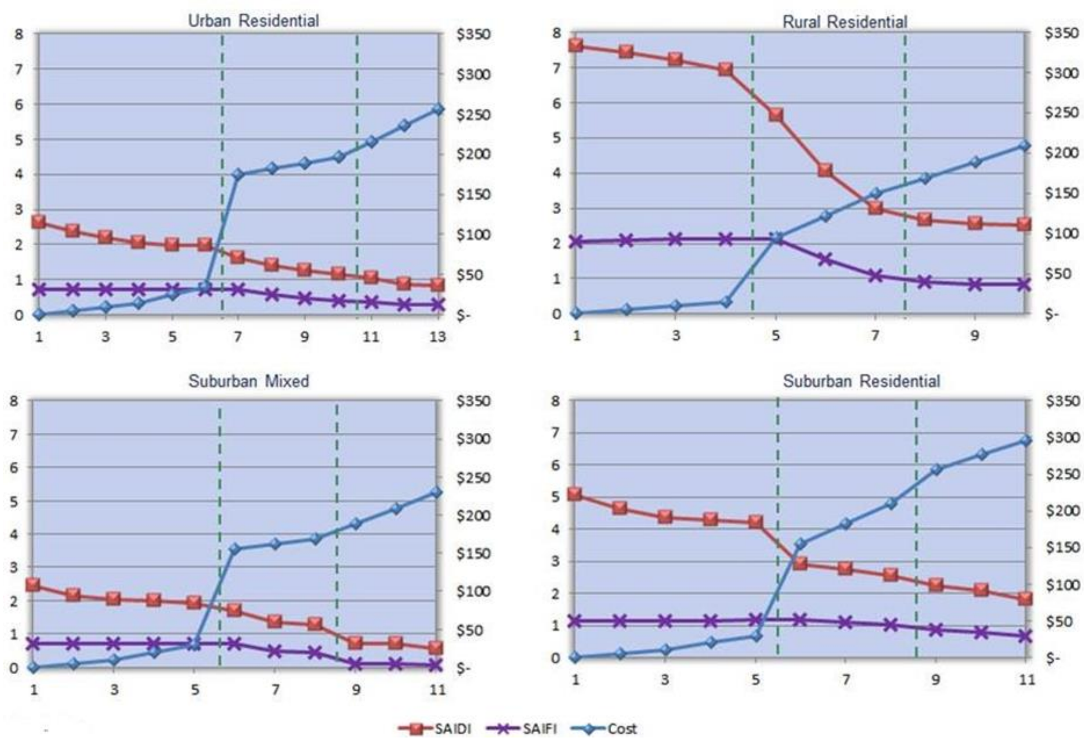

Figure 5-5 Example of circuit simulation results for various SG-DA scenarios

More recently, the GE team evaluated the dollar benefits of outage reduction, using the outage values reported in the DOE "Interruption Cost Estimator", based on the DOE/LBNL study described previously.[63]

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[60] CYMDIST™, licensed from CYME International.

[61] Work described in this section is proprietary and includes both research conducted for the multi-utility consortium DSTAR (www.dstar.org), which GE administers, as well as work that is internal to GE, under funding from the GE Digital Energy Software Solutions business. Results of this work can only be made available in summary form.

[62] DSTAR 13-10: "Impact of Smart Grid on Distribution Reliability"; Matt Lecar, Suresh Gautam, Lavelle Freeman.

[63] LBNL-2132E, "Other Estimated Value of Service Reliability for Electric Utility Customers in the United States", Lawrence Berkeley National Labs, June, 2009; Sullivan, Mercurio, and Schellenberg.

While still preliminary, the results achieved thus far are consistent with the anecdotal information from the ARRA stimulus projects, previous business case work performed by GE, and direct "voice of customer" interviews:

- Reductions of 20-40% in SAIDI and SAIFI[64] are achievable for many different kinds of circuits, using a combination of automated field devices (sensors, switches, and reclosers) and either decentralized or centralized (DMS-based) control.
- These results vary by feeder topology and customer mix and density
- The dollar value of customer benefits for investment in DA appears to justify targeted investment to those circuits likeliest to show the biggest "bang for the buck."
- The potential reliability benefits appear to saturate at higher levels of investment, short of system wide deployment of full, closed-loop automation.[65]

5.4.5 Application to Storm Resiliency

The benefits methodologies described above share in common an expression of the societal value of outage reduction based on the cost of customer outages (per event of a given type) times the number or rate of such outages predicted to be avoided by a given SG-DA intervention. For ordinary reliability, metrics of outage performance are readily available in the form of SAIDI and SAIFI statistics, which are published and maintained for most North American utilities. As discussed above (see Section 5.4.2), there is a basis in the literature for ascribing a value to the costs of outages of different duration for customers of different types.

Major storm events, however, are explicitly excluded from the conventional reliability indices. Major events, such as a Hurricane Sandy, cause damage that is different in scale, duration, and kind from more ordinary reliability events (including both "blue sky" outages and run-of-the-mill storm events). Any methodology for estimating the benefits of SG-DA (or other utility investments in storm hardening) must begin by defining a metric of resiliency performance against which improved performance can be judged.

In Chapter 2 of this report, GE reviewed the Major Event Reports of the New Jersey EDCs and recommended improvements to the MER format that would permit more consistent and standardized benchmarking of utility storm recovery performance. GE believes the same data collected from the revised MER format can also form the basis for assessing the resiliency benefit of the EDCs SG-DA deployments.

For example, GE recommends that data be collected from the EDCs on the number of customers restored to service at different time intervals following the onset of a major event (1 day, 2 days, 3 days, etc.) for each affected circuit. During post-storm evaluation, these data should be analyzed for statistical patterns of faster recovery for circuits with DA versus similarly situated circuits without DA (controlling for relevant circuit attributes such as voltage, topology, customer mix and density,

[64] Consistent with the ARRA reported results described in 5.1.1, SAIDI was reduced more than SAIFI.

[65] One reason this may occur is because the automation captures the available "entitlement" – that is, the reduction in the number and duration of outages that can readily be achieved through faster detection, location, and isolation of faults, and automated service restoration. There will still be a residual level of outages, for example for faults involving more serious or permanent damage to utility assets, where service cannot be restored to affected customers until a field crew is able to physically repair or replace the damaged equipment.

as well as relative storm exposure). Based on the results of such an analysis, the BPU could then define a metric, such as the total customer-days of outage for a given event, and assign a dollar value to each unit of reduction in the metric (i.e. improvement in resiliency) achievable through incremental investment in SG-DA. Importantly, such analysis would provide the BPU with an empirical basis for targeting SG-DA investment to those circuit types and locations likely to see the "biggest bang for the buck" in terms of storm resiliency improvement.

The opportunity to inform BPU SG-DA decision-making through better reporting and analysis of future storm performance forms the basis for GE SG-DA Recommendations SG-2 and SG-3 (see Section 6.4).

Recommendation SG-2: Target deployment plans to evaluate SG-DA technology effectiveness for resiliency by strategic deployment on subsets of circuits with similar storm exposure and physical attributes.

Recommendation SG-3: Define and mandate reporting requirements to track effectiveness of SG-DA technologies in storm recovery activities.

6 SUMMARY OF KEY RECOMMENDATIONS

6.1 Major Event reporting Recommendation

6.1.1 Recommendation MR-1: Upgrade EDC MER requirements

a. *Enhance standard reporting requirements to collect additional data*

b. *Provide data collection and reporting templates to drive consistency*

c. *Develop performance standard and assessment scorecard for post-event analysis*

Rationale

- The Commissioners have expressed their need to assess the extent of damage to grid equipment, with causes of damage assigned (e.g. wind, trees, flying debris, inland flooding, storm surge, poor design, etc.).
- Following this recommendation will improve quality and consistency of MERs and enable BPU staff to perform comparative analyses to objectively assess: how much damage was caused by this event relative to previous events; speed of restoration vs. severity of damage; restoration crews applied as a function of the scale of damage; what factors contributed to response time. This recommendation blends best practices from MD and NY.

Necessary Data

- Define types of utility equipment to be tracked.
- Define categories of restoration costs of interest, including equipment, crew-hours, T&L, ancillaries, etc.).
- Define causes of storm-related damage to be collected.

Possible Implementation Steps

- Define consistent data collection templates for restoration effort and equipment tracking (see examples in Section 2.2).
- Define standardized comparison graphs and charts to facilitate clear understanding of damage extent and root cause (e.g. temporal plots in Section 2.2).
- Develop performance standard and scorecard methodology for assessment of EDC storm response performance.

6.2 Distribution Hardening Recommendations

6.2.1 Recommendation DH-1: Track off-ROW trees; predict and report outages, damage, ETR

Track off-ROW trees posing risk of outages; predict and report associated damage, number of customer interruptions, and restoration time by danger tree.

Rationale

- Following this recommendation will provide insight into the number of danger trees and the potential damage. This will enable informed decisions on whether the risk is acceptable or mitigating actions are needed. It will also allow prioritization of actions by level of risk.
- EDC forestry departments already routinely identify danger trees within the clearance zone, but not all keep data on off-ROW danger trees (only ACE reports doing so).
- Causes of outages are typically captured in databases that may or may not be integrated with other data sources. JCP&L, for example, uses PowerOn as their causation database and includes classification of vegetation-related outages as preventable (within ROW) or non-preventable (off-ROW)[1].
- Data on tree-related outages should be reported in EDC major event reports and the extent of infrastructure damage, customer outages, and delays in response due to off-ROW trees should be highlighted.

Steps for Predicting Damage

- Apply fault to system model at location of danger tree.
- Count number of interrupted customers and total the unserved MW.
- Estimate worst-case damage due to event (broken pole, downed wire, damaged transformer, insulators); report using standard damage assessment forms.
- Simulate restoration process and estimate time to restore customers.
- Calculate and report total unserved MWh by customer class.
- Prorate and report total interrupted customers and unserved MW/MWh by probability of weather events.

6.2.2 Recommendation DH-2: Segment customers; calculate/report hours out due to trees

Segment customers by restoration priority; calculate and report an estimate of hours out-of-service due to tree damage during normal weather for each customer.

Rationale

- Customers who are served by circuits adjacent to off-ROW danger and hazard trees will eventually be interrupted by tree-related events, whether during storms or blue-sky days.

- Not all customer s are equally impacted: customers with a sectionalizing device between them and the tree can potentially be restored faster; high priority customers are typically targeted for earlier restoration during storms.
- This recommendation will give BPU insight into the degradation in service due to off-ROW trees.

Necessary Data

- Type of customers, criticality and location overlaid on system map.
- Location of danger trees overlaid on system map.
- Probability of event relative to weather driver categories (ice, wind, snow, storm intensity etc.).
- Number expected storm days/year representative of weather drivers.

Steps for Assessing Customer Impact

- Categorize customers in affected area by level of exposure and remediation, and restoration priority.
- Apportion duration of circuit outages due to off-ROW tree fault events (from #1) to affected customers.
- Aggregate number of hours out of service interruption per year for each customer due to events.
- Prorate hours out due to tree damage by probability of weather events; report results.

6.2.3 Recommendation DH-3 Communicate estimates; provide mechanisms for reporting

Communicate estimates to customers and provide convenient mechanisms for customers to report danger trees (e.g. via Twitter feeds).

Rationale

- According to a J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study, the more information customers receive about outages the more the more positive they are about their utility's performance.
- If individual customers and local communities are given clear, quantitative information on the potential of specific off-ROW danger trees to negatively impact their quality of service, they are more likely to work with the utility in finding ways to improve reliability and resiliency.
- Social media is a natural and convenient tool for motivated customers and local communities to interact with the utility and provide information about potential hazards. Encouraging the use of crowd-sourcing will focus utility efforts and thus reduce costs.

- This recommendation will give customers specific information on the risk of outages and expected number of hours out due to off-ROW trees and potentially drive their engagement with EDCs.

Implementation Steps

- Report estimates to individual customers and communities via cost-effective means (e.g. social media, bill inserts, door hangers).
- Track and prioritize customers and communities with the highest number of potential outage hours.
- Create a process to integrate customer feeds (e.g. SMS, emails, smartphone pictures via Twitter or Instagram) of danger trees, or suspicious utility infrastructure into inspection processes

  "Hey @PSEGdelivers this old tree will fall over my line soon #DangerTree"

6.2.4 Recommendation DH-4: Grant EDCs authority to remove off-ROW danger trees

Where justified, grant EDCs the authority to remove danger trees outside the clearance zone.

Rationale

- Off-right-of-way trees accounted for a significant amount of damage in NJ during recent storms. Following this recommendation will initiate the appropriate legislative process to grant utilities the authority to remove off-ROW trees with highest impact on the ratepayers.
- Some state regulatory decisions or legislative proposals give utilities more authority to address off-ROW trees:
  - CA Case R08-11-005: Conditionally authorizes utilities to turn off power supply to property owners who block VM activities around overhead power lines.
  - CT H.B. 5551: Proposal to (1) allow companies that provide electric or telephone services to acquire by eminent domain a tree or shrub that is on or adjacent to an existing right-of-way or easement held by the company if the company determines that such tree or shrub would cause a interruption in the delivery of such service due to the condition of the tree or in the event of a storm accompanied by winds of hurricane force, snow or ice, and (2) make technical changes.
  - IL H.B. 3884: Provides that it shall be unlawful for any person to plant restricted vegetation within 20 feet of an electric utility pole or overhead electrical conductor located within the State. Provides that any restricted vegetation planted, whether by a person or by natural means, within 20 feet of an electric utility pole or overhead electrical conductor located within the State shall be subject to removal.

Possible Implementation Steps

- Rank danger trees based on predicted damage (from earlier Recommendation).
- Develop jurisdiction-specific approaches for extending utility authority.

6.2.5 Recommendation DH-5: Determine the most cost-effective level of tree-trimming

Determine the most cost-effective level of tree-trimming and optimal corridor width by circuit or segment using vegetation data and other relevant inputs.

Rationale

- The goal of this recommendation is to specify tree-trimming cycle and corridor width at the circuit segments to maintain or improve reliability and resiliency by cost-effective VM practices.
- NJ 14:5-9.4(b): "An EDC shall perform vegetation management on vegetation that is close enough to pose a threat to its energized conductors at least once every four years."
- All NJ EDCs trim on a 4-year cycle in compliance with NJ 14:5-9.4(b) ; ACE and PSE&G report incorporating CBM or a model to prioritize circuits.
- Rather than keeping to a rigid cycle, GE recommends that EDCs collect and aggregate data for use in reliability-centered vegetation management:
  - Historical line failures and associated customer interruptions
  - Circuit-level reliability indices (SAIDI, SAIF, CAIDI, MAIFI)
  - Customers out, restoration times, equipment damaged/replaced during past storms
  - Vegetation density, species, growth rate, location of danger trees relative to circuits.

Steps to Determine Level of Trim

- Determine statistical correlation between trim cycle and circuit reliability, and between corridor width and circuit reliability
- Use transfer function to adjust circuit failure rates by segment to simulate changes in VM practices
- Calculate a response surface to quantify change in segment reliability due to changes in trim cycle and corridor width
- Use the results to choose optimal level of trim per segment to achieve a specified expected level of reliability
- Use expected level of reliability as a sensitivity variable and quantify incremental change in VM costs

6.2.6 Recommendation DH-6: Selectively underground most critical feeders and tap lines

Selectively underground the most critical distribution feeders and tap lines, where practical, to improve reliability and reduce major storm restoration time.

Rationale

- Jurisdictions and states that have considered undergrounding, have selected circuits with attributes that make it technically and economically feasible. This recommendation provides the BPU with a methodology to select appropriate candidate feeders and segments for undergrounding

Necessary Data

- Location of circuit (e.g. coastal, mountain, urban, rural, etc.)
- Physical attributes of circuits (e.g. age, construction type, soil type, etc.)
- Number of customers, type and restoration priority (or criticality) by circuit
- Historical reliability and storm performance of feeders
- Probability of weather event impacting circuit (i.e. exposure or vulnerability to ice, wind, snow storm etc)

Steps to Determine UG Candidates

- Determine attributes that make circuits/segments/taps good candidates for UG (consider performance of existing UG circuits). Examples of attributes include: reliability issues; past storm damage and restoration times; customer count; critical loads served (hospitals, emergency services, etc.); age/eligibility for upgrade or replacement; ongoing excavation or construction.
- Assign weights to the attributes to reflect importance.
- Score circuits with regard to each attributes and determine weighted multi-criteria score for each circuit.
- Select and <u>evaluate</u> top ranked candidates for undergrounding.

6.2.7 Recommendation DH-7: Determine the most cost-effective inspection cycle/method

Determine the most cost-effective inspection cycle and method for poles and associated equipment by circuit, and prioritize based on criticality and condition.

Rationale

- NJ is considering mandating annual inspections for resiliency reasons. Total estimated cost is $24 million/year. However, data show that the frequency of inspection may be <u>less</u> important than the method of inspection.
- This recommendation will require EDCs to prioritize inspection based on criticality and condition and allow for more rigorous methods than may be possible on an annual cyclic basis, ultimately leading to more effective use of the inspection budget.

Necessary Data

- Historical failures, associated customer interruptions linked to deteriorated poles or equipment.
- Circuit-level reliability indices (SAIDI, SAIF, CAIDI, MAIFI).

- Customers out, restoration times, poles and associated equipment damaged/replaced during past storms.
- Inspection/maintenance records.

Steps to Determine Inspection Cycle/Method

- Determine statistical correlation between inspection cycle/method and circuit reliability.
- Use transfer function to adjust failure rates by segment to simulate changes in inspection practices.
- Calculate a response surface to quantify change in circuit reliability due to changes in inspection cycle/method.
- Use the results to choose optimal level of inspection to achieve a specified expected level of reliability.
- Use expected level of reliability as a sensitivity variable - quantify incremental change in inspection costs.

6.2.8 Recommendation DH-8: Upgrade construction near coast; design for extreme loading

Upgrade T&D construction near coastal areas to NESC Grade B, and incorporate extreme wind and ice loading criteria in all T&D design, regardless of height.

Rationale

- In New Jersey, the areas within 10 to 15 miles of the coast are particularly exposed to extreme winds with a mean 50-year recurrence (NESC 250C) and extreme ice and concurrent wind with a mean 50-year recurrence (NESC 250D).
- Undergrounding circuits near the coast may be problematic due to high likelihood of storm surge and flooding.
- Upgrading circuits “near” the coast to Grade B construction (which is 50% stronger than Grade C used for most distribution lines) will lead to more resilient structures.

Necessary Data

- Number of T&D circuit structures, construction grade, total length (miles), number of poles, towers and other structures within a set distance (e.g. 10 miles) of the coastline.
- Historical damage records for construction near coastal areas
- Exposure/vulnerability of circuits near coast to storm damage

Steps to Determine Construction Upgrades

- Analyze historical weather data to determine impact of flooding/storm surge vs. distance from coast
- Assess damage to OH T&D structure (due to wind, trees, ice, snow, etc…) vs. distance from coast

- Consider historical reliability, and criticality of the circuit in terms of number and priority of customers
- Determine optimal distance from coast and prioritize feeders for upgrade

6.2.9 Recommendation DH-9: Insert steel/concrete structures in long straight wood circuits

Insert steel or concrete structures in long straight circuits with wood structures to prevent cascading failures (domino effect); alternatively reinforce wood poles with steel bands.

Rationale

- Structural damage constitutes a majority of damage to transmission and distribution lines during extreme wind, hurricane or extreme ice build-up. Failure of structures causes additional stress on neighboring structures. The stress can build up and propagate to neighboring structures causing a cascading failure. This is a phenomenon responsible for failure of wood pole construction, especially long straight lines in open areas.
- A more resilient stronger structure is required to break the domino effect and halt cascading failures. Steel, concrete and composite structures provide this strength and can help reduce the damage to T&D lines. Alternatively, steel bands may be added to existing wooden poles for reinforcement.

Necessary Data

- Circuit location and construction information
- Historical storm damage and failure modes for circuits

Possible Implementation Steps

- Analyze historical records for instances of cascading failures
- Inspect and assess transmission/distribution for possible vulnerability to cascading failures,
- Determine structures to be replaced to prevent cascading failures

Example Outputs

- Circuits that can be reinforced with stronger structures to prevent cascading failures
- Location and number of reinforced structures to insert

6.3 Substation Hardening Recommendations

6.3.1 Recommendation SH-1: Add elevation attributes to flood-prone assets and report

Add elevation attributes to every flood-prone asset in a substation equipment database; report number of assets below the 100-year flood and storm surge elevation plus 1 foot.

Rationale

- Several substation equipment failures occurred due to water infiltration during the recent storms

Necessary Data

- Elevations of substation equipment or equipment components susceptible to flood damage
- 100-year flood elevation and FEMA advisory base flood elevation at equipment locations

Steps to Determine Assets Subject to Flood Damage

- Define critical elevation for each substation site as the 100-year flood elevation or the FEMA advisory base flood elevation plus 1 foot, whichever is higher

(Note: the following steps are only for those substations that could contain equipment susceptible to flood damage; i.e. if the substation yard grade is well outside of the 100-year flood plane)

- Review of existing station drawings for equipment and elevation information
- Conduct site surveys for equipment and elevation information
- Create or add to existing Geographic Information System (GIS) databases

6.3.2 Recommendation SH-2: Perform limited failure modes and effects analysis (FMEA)

Perform limited failure modes and effects analysis (FMEA) for substations using weather events as the modes with customer outages and substation equipment failure as an effect; report findings.

Rationale

- A Failure Modes and Effects Analysis (FMEA) can provide a relative risk of a substation equipment failure for use in prioritizing repairs or inspections.

Necessary Data

- Asset elevation database from Substation Hardening Recommendation #1
- Weather event definitions along with probability of recurrence

Steps to Determine Risk priority Number for Critical Equipment

- Determine critical equipment failure and failure combinations that will result in a customer outage.
- Determine the relative probability of failure for each piece of critical equipment (0 to 10 scale: 0 = will not fail, 10 = failure is certain) during a specific weather event.
- Determine the relative severity of critical equipment failure (0 to 10 scale: 0 = will not cause a customer outage at failure, 10 = customer restoration > 1 week).

6.3.3 Recommendation SH-3: FMEA findings, estimate and report hardening costs

Rank findings, estimate and report costs of hardening substation equipment to eliminate the top 20% of equipment failures leading to customer outages as identified in SH-2.

Rationale

- Based on the Pareto principle, protecting or relocating approximately 20% of flood susceptible equipment in substations should eliminate approximately 80% of substation outages due to flooding and storm surges.

Necessary Data

- Asset elevation database from Substation Hardening Recommendation SH-1
- Analysis results report from Substation Hardening Recommendation SH-2

Steps to Determine Prioritized List and Costs

- Quantify the number of customer outages that are associated with each potential equipment failure due to flood damage
- Rank equipment failures based on number of outages caused by the equipment failure
- Estimate costs associated with hardening equipment for a prescribed percent of the worst ranked equipment. In hardening, options are flood avoidance, (e.g. vertical relocation), flood control, relocation, retirement and alternate supply.
- Select the desired percent of the worst ranked equipment to prioritize for hardening, considering cost of hardening as well as reduction in outages

6.3.4 Recommendation SH-4: Estimate and report costs of inspection; optimize cycles

Estimate and report costs of regular inspection for critical assets as identified in recommendation SH-2; optimize inspection cycles to achieve highest impact with lowest cost.

Rationale

- This recommendation introduces consideration of the risk of storm damage and its impact into planning of inspection and maintenance (I&M) cycles of utility substations.
- I&M cycles can be adjusted to account for their criticality during storms.
- Regular I&M of support structures that are susceptible to storm damage and have significant impact on customers is equally important but may often be overlooked.

Necessary Data

- Analysis results report from SH Recommendation SH-2
- List of assets from SH Recommendation SH-3 not selected for hardening
- Utility maintenance schedules and procedures for assets to be inspected
- In-service and maintenance records for assets to be inspected

Steps to Determine Inspection Cycle for Critical Assets

- Review existing maintenance schedules and records against critical asset list
- Where inspection procedures for critical asset are unavailable, develop procedures
- Estimate inspection costs for critical assets in accordance with defined procedures
- Determine inspection schedule based on cost and ranking from SH Recommendation SH-3

6.3.5 Recommendation SH-5: Identify critical communication facilities; estimate hardening costs

Identify and report communications facilities critical to restoration process; estimate and report costs of providing backup power to cover 3-sigma of expected storm restoration time.

Rationale

- Utility communications are essential for control and monitoring of power system devices and for coordination of many aspects of operation, maintenance and emergency response. During outages precipitated by storms and other catastrophic events, a secure backup power supply is needed to provide emergency power to the facilities performing communications and coordination functions.
- Based on recent history, storm-related outages can last from a few hours to over a week. Communication facilities are a high-priority restoration target, but it may still take several hours to restore power after a storm. How much backup is needed?

Necessary Data

- List of central offices and communication facilities critical to restoration process
- Existing backup power configuration/procedure, (batteries, diesel, gas, combination, fuel supply/acquisition)
- Historical duration of major storms and time to restore power to critical communication facilities
- Backup generator configuration to cover *'3-sigma'* of storm outage duration: secure on-site fuel storage for one (1) day, replenish fuel supply on day 2 after outage (and daily thereafter as necessary).

Possible Implementation Steps

- Determine statistical period that covers 3-sigma (e.g. 99.7% if normally distributed) of communication facility outages during past storms
- Estimate the configuration and cost of backup generation to cover 3-sigma period (installed cost, fuel, O&M)
- Identify communication facilities critical to restoration process with insufficient backup for 3-sigma duration

- Estimate costs to upgrade communication facility backup power supply to cover 3-sigma of storm restoration duration

6.4 SG-DA Recommendations

6.4.1 Recommendation SG-1: Asses/deploy most impactful SG-DA technologies

Mandate that EDCs assess impact of reliability-oriented SG-DA and create investment and deployment plans for the most impactful technologies for their service territory.

Rationale

- EDCs should base their investment and deployment plans for reliability-oriented SG-DA based on an impact assessment.
- This recommendation is motivated by GE team's investigation, as described in Section 5.4.3, indicating that SG-DA technologies would be expected to have a significant impact on reducing the outage times. The expectation is based on the current impact of SG-DA on reducing the outage times during blue sky events (i.e., reliability impacts).
- Since models for assessing SG-DA "resiliency" impact and the associated cost/benefits do not presently exist, an investment screening can be based on a "reliability" assessment model, which is possible today, which would provide a "floor" for the expected resiliency benefits. Investments that are cost-effective under ordinary circumstances and can provide additional benefits during major storms should be approved. However, it should be noted that there is no "one size fits all" solution, since diverse service territories with different circuits behave differently under DA.
- SG-DA has been proven to restore service faster to more customers, and reduce extent of prolonged outages. Future investments should target SG-DA to those circuit types and locations that provide the best "bang for the buck," that is, where the value of reliability improvement exceeds the cost to ratepayers.

Possible Implementation Steps

- An approximate circuit type methodology: Example of an approach and methodology is provided in Section 5.4.
- Comprehensive Data Analytic Simulation: This approach is based on modeling of actual EDC distribution system with accurate representation of individual circuits. Evaluation of reliability impacts (i.e., shortening of outage times) on each circuit due to different levels of complexity of Integrated DSM will be computationally intensive and rely on full-fledged utility analytics and detailed information on EDC distribution circuits

Necessary Data

- Circuit models of EDC systems
- Historical reliability and operating data
- Parameters defining attributes of incremental DA improvements

- Interruption Costs (i.e., VOLL) by customer type and interruption interval, for example:
    - o BPU could assign benefits dollars to different customer class outages (DOE/LBNL Method in Section 5.4.2).
    - o BPU could set a cost threshold per outage avoided (Duke Method in Section 5.4).

6.4.2 Recommendation SG-2: Deploy SG-DA technology selectively for resiliency

Target deployment plans to evaluate SG-DA technology effectiveness for resiliency by strategic deployment on subsets of circuits with similar storm exposure and physical attributes.

Rationale

- Blue Sky reliability assessment methodologies exist, but major storm resiliency impact is harder to evaluate, since major storm events are rare and are excluded from the reliability indices.
- As EDCs submit deployment plans, BPU can create selection criteria to target a subset of deployment to areas with high storm exposure in order to measure the reduction in restoration times compared to similar areas without such deployments.

Possible Implementation Steps

- The recommended implementation step is to create selection criteria for targeted resiliency deployments on circuits with similar storm exposure and physical attributes.

Necessary Data

- EDC Standard Report submittals which should include their SG-DA deployment plans (Recommendation SG-6).
- EDC feeder map with locations of DA equipment and feeder physical and electrical characteristics (Recommendation SG-6).
- Major Event Reports (MERs): MERs are discussed in Chapter 2; they should include separate reporting of performance of DA and non-DA circuits.

6.4.3 Recommendation SG-3: Track and report SG-DA effectiveness during storms

Define and mandate reporting requirements to track effectiveness of SG-DA technologies in storm recovery activities.

Rationale

- Analytical models for projecting SG-DA "resiliency" impact and the associated cost/benefits do not presently exist.
- However, EDCs can collect actual/empirical information from future storm events in order to quantify the resiliency and storm recovery impact of implemented SG-DA on their system in order to assemble resiliency impact data that can be used to assess additional SG-DA investments. This recommendation is the next step to Recommendation SG-2.

Possible Implementation Steps

- Define a "resiliency/storm recovery" metric; for example: area under Customer Outage Duration Curve
- Make a map/database of the distribution system/ individual circuits with their SG-DA type attributes.
- Segregate/classify circuits by their level of SG-DA attributes (e.g., high, medium, low, or some other characteristics).
- Monitor and track the restoration times by circuit segments/classes after each storm event.
- Collect and analyze the data to understand the relationship between DA and resiliency/storm recovery.

Necessary Data

- EDC feeder map with locations of DA equipment and feeder physical and electrical characteristics
- Number and types of customers affected by storm events and their outage times on each circuit

6.4.4 Recommendation SG-4: Require EDCs to evaluate damage prediction tools

Require EDCs to quantify potential improvement in damage forecasts using storm tracking and damage prediction tools, and assess resulting improvement in storm response.

Rationale

- As part of ERP, EDCs must discuss how to track, predict damage, and prepare for major storms. This recommendation takes it to a higher level based on data analytics and system simulation.
- If evaluation warrants eventual implementation, the advanced data analytics software will leverage the full range of historical and real time weather and utility data to perform analysis of circuit and equipment failure potential, anticipate number of outages, identify high likelihood locations, and determine crew requirements and full system restoration times.

Possible Implementation Steps

- Traditional Analytics are based on asset failure due to a given storm forecast path. In contrast, Predictive Analytics are based on historical and real-time meteorological data, and utility system configuration and equipment data from SCADA, OMS, DMS, and data received through social media.
- For Testing, EDCs can provide the historic weather and system assumptions to the software vendor to perform a back-casting simulation. EDCs would then compare the vendor's back-cast with the actual historical EDC storm damage data (see Section 5.2.2 and Section 9.6 in Appendix C).

Necessary Data

- Data needed include EDC distribution system topology, system design and layout, equipment, customer density, vegetation, plus extensive history of weather conditions and storm damage.

6.4.5 Recommendation SG-5: Assess value and feasibility of DG and microgrids

Continue to look at the value of microgrids and back-up generation to the state consistent with the energy master plan, and initiate techno-economic feasibility studies where practical.

Rationale

- A primary objective of grid resiliency is to ensure uninterrupted operation of the critical services needed during major storm events.
- Critical facilities require higher levels of resiliency. Hence, the need for back-up generators, and microgrids if warranted, that can act as single controllable entities and operate in isolation from the grid when needed.

Possible Implementation Steps

- Identify candidate sites; perform supply and demand analyses; select generation mix based on levelized cost of energy (LCOE); assess electrical, communications and control infrastructure needs; perform cost benefit analysis.
- If feasibility analysis is favorable, promote policies and directives that facilitate back-up generation or microgrid deployments in critical and essential public service locations.

Necessary Data

- Site location, electricity (and heat) supply and demand (load profiles), load projections under emergency situations, site infrastructure information (on-site generation, and electrical, heat, communication, and fuel delivery networks), feeder interconnection system, applicable utility rates, relevant ISO markets rules and qualifications, if applicable, etc.

6.4.6 Recommendation SG-6: Mandate standard EDC *SGDAP* reporting

Mandate enhanced EDC SGDAP submissions to ensure completeness, and to enable comparative evaluation and benchmarking of SG-DA investment plans.

Rationale

- As highlighted in Section 0, EDC BPU-63 and 65 SG-DAP submissions do not include information on the full range of SG-DAP components and their "timeframe, costs, and benefits" as required by the BPU-63 and 65.
- Since the current EDC SG-DAP submissions are not based on a standard framework, they do not allow comparison and benchmarking across EDCs, or any assessment of the economic viability of the EDC plans.

- A standardized and comprehensive approach will enable comparison against BPU requirements, help identify SG-DAP technologies considered or used by the EDCs, and enable comparisons across EDC plans and benchmarking with other utilities outside NJ.

Possible Implementation Steps

- A recommended action item is for the BPU to require the EDCs to submit a Standard Report and Information Checklist that would enable comparison across EDCs and benchmarking with other utilities.
- The Standard Report should include requirements for EDCs to provide complete information on specified items. The Standard Report template should cover all aspects of SG-DAP that would enable the BPU to evaluate the current and future plans by the EDCs in terms of their feasibility, reliability and resiliency impact, and expected costs and benefits. Examples of items to be covered are provided below.
- The Standard Report can include additional survey type questionnaire section, similar to the Appendix C of the Quanta Report.[1]
- To compare the EDC submittals across EDCs, BPU should score the EDC plans using an approach similar to the Carnegie Melon Smart Grid Maturity Model.[2]

Necessary Data

- Description: Explanation of the technology or device. Examples of device attributes are: class/type (e.g., midpoint or tie recloser), main function (e.g., VAR or CVR control), location (storm-prone or storm-safe) or scale (pilot or wide deployment).
- Current Status: Existing state of the technology deployment. Examples: number of existing devices, percentage of feeders with the technology already implemented, or number of customers covered.
- Future Plans / Timeframe: Plans for future technology deployments with project timeframe. Examples: rate of substation modernization per year or number of years to finish the project.
- Cost to EDC: Breakout of yearly costs of the technology. Examples: according to cost type (e.g., capital and maintenance) or according to the technology component type (e.g., circuit, automation and communications).
- Cost to Ratepayers: Proposed ratepayer's contribution (e.g., rate increase) for the technology deployment.

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1 Quanta Technology, "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs", Prepared for Public Utility Commission of Texas, Project No. 36375, Richard Brown, March 4, 2009 (Appendix C). http://www.puc.texas.gov/industry/electric/reports/infra/utlity_infrastructure_upgrades_rpt.pdf

2 Carnegie Mellon University, "Smart Grid Maturity Model, Software Engineering Institute", October 2010. http://www.sei.cmu.edu/library/assets/brochures/sgmm-1010.pdf

- Benefits to EDC: Description and quantitative analysis of the technology benefits to EDC (e.g., reliability or efficiency). Efficiency benefits are due to associated cost savings/cost reductions/cost avoidance.
- Benefits to Ratepayers: Description and quantitative analysis of the technology benefits to ratepayers. Example: The output of Recommendation SG-1, i.e., Benefits to Ratepayers in terms of reduction of customer interruption costs.

7 APPENDIX A – BPU-63 AND BPU-65 ORDERS

7.1 BPU-63 Ordered Action

"Each EDC currently managing or evaluating a Smart Grid pilot program incorporating Distribution Automation within NJ or the PJM region and each EDC that is in the process of developing and implementing any new Smart Grid- Distribution Automation pilots shall submit to Staff a status report explaining the scope of work, objectives/goals, tasks, funding source including federal, state, regional or energy organization, schedule and any other pertinent information."[1]

7.2 BPU-65 Ordered Action

"Each EDC shall file a Smart Grid – Distribution Automation Plan (SG-DAP) filing. The SG-DAP shall include the development and implementation of feeder and substation automation as part of an overall Distribution Management System (DMS) and Outage Management System (OMS). The SG-DAP shall, including [sic] but not be limited to the following: Automatic circuit re-closures (ACR), automation sectionalizing and restoration (ASR), advanced voltage control, VARs control, network protection/monitoring/controls, remote terminal units, remote fault detection, smart relays, equipment health sensors, outage detection devices and smart meters."

"The SGDAP filing shall include the timeframe for the development of each component and the overall plan, as well as the costs and benefits of each individual component and the entire plan to the EDC and the ratepayer. The SG-DAP shall be developed with the goal to implement a more resilient and "self-healing" distribution grid operation overall with a specific focus during and after a storm events [sic] such as Irene."

"The Division of Energy will review and evaluate the Smart Grid – Distribution Automation Plan filing to determine the benefits of adopting and utilizing Smart Grid - Distribution Automation strategies within New Jersey's electric distribution systems. Additionally, Staff will review the results of the Distribution Automation pilot programs, currently in progress by several of the EDCs, to evaluate the realized benefits and potential constraints with such implementation. This review should include the EDCs' current implementation of substation SCADA systems, protective relaying, use of dynamic recording devices, smart metering, automated circuit switching and closing, and other power quality and equipment monitoring technologies. Staff will perform an independent cost and benefits review of each of the EDCs Smart Grid – Distribution Automation Plan including Cost and benefit considerations as well as rate impacts associated with the implementation of the EDC Smart Grid - Distribution Automation will be reviewed."[2]

[1] State of New Jersey Board of Public Utilities, Docket No. EO11090543, "*In the matter of the Board's Review of The utilities' Response to Hurricane Irene*," Agenda Date: 1/23/13, Page 58

[2] Ibid.

8 APPENDIX B - ELEMENTS OF STORM RESPONSE

Storm response begins long before an event occurs and continues long after the worst is over. The term "response" is specifically chosen to encompass everything the utility does to actively prepare for, combat and recover from a storm event. The most important factor that determines the impact of a storm event is how the electrical system is designed, constructed, and maintained to withstand storm forces and elements. Some of the key elements of the storm response are summarized below[1]. Across most of these elements, distribution automation and Smart Grid technologies can be utilized to improve efficiency, reduce downtime, ensure safety and provide critical feedback.

8.1 Before the Strom

8.1.1 Storm Hardening

Storm-hardening activities aim to reduce the impact of future storms by assessing the infrastructure to identify ways to make it more resilient. State Utility Commissions are paying more attention to storm hardening as a result of the fallout from recent, particularly devastating storms, and the increase in customer complaints. Some of the more common storm hardening activities include: tree trimming/vegetation management, system design changes, and maintenance activities such as pole inspection/replacement programs.

8.1.2 Preparation and Training

Besides hardening the system to withstand the impact of a storm, the next most effective activity is preparing and training for storm restoration. This includes all activities that enable utility mobilization and power restoration as soon as possible after a storm, and ensure continuity of business operations. Best-in-class performers develop and maintain a comprehensive emergency response plan (ERP), to guide response during major events. A good ERP provides a uniform, corporate-wide approach for managing an emergency, defines roles, responsibilities and accountability, documents recovery procedures, and provides a business continuity plan (BCP) to maintain or re-establish business operations following a disruptive event. Preparation also includes flexible training options for storm duty personnel, evaluation of effectiveness by testing and measuring, and annual storm drills to exercise and refine all phases of the ERP.

8.1.3 Storm Tracking

All storm events are not created equally and so it is inherently difficult to predict and forecast certain events. Tornadoes, for example, typically have the shortest lead-times. Advanced warning may be several hours during an active spell, severe thunderstorms or other conditions that spawn tornadoes, or much less than an hour for sudden outbreaks. Hurricanes on the other hand, have relatively long lead times. A utility can typically have anywhere from three (3) to fourteen (14) days of advanced warning that a hurricane is headed its way. In any case, there are several products and services that can provide advanced warning to allow for better planning and mobilizing.

[1] From DSTAR Project 11-7, Best Practices for Utility Storm Response, June 2008, http://www.dstar.org/research/project-desc/StormResponsePractices/

8.1.4 Damage Prediction

Once a storm is imminent it is important to have good damage prediction methods in place. The goal is to forecast the amount of damage a storm will produce (poles broken, transformers damaged, miles of primary and secondary down, customers out, trees down/damaged), the resources required for restoration, and the approximate time to restore service. Damage prediction is an essential part of the storm management process, providing triggers for levels of storm center activation and crew mobilization. Prediction tools range from simple storm classification tables, based on current data and past information, to more sophisticated computer models that take into account other system variables like topology, system design and layout, customer density and vegetation.

8.1.5 Activation and Mobilization

The first step in responding to a storm emergency is to activate the storm organization. A best practice is to provide mobilization triggers for various stages of advanced planning. Some utilities develop a categorization method that prescribes levels of activation based on storm characteristics. These categorization methods and activation levels can vary greatly from utility to utility based on factors like geographic location, size, customer base, etc. The table below shows one example from a mid-sized utility commonly exposed to winter storms.

1. **Level Zero** (normal conditions)
   - Dispatching from Central Dispatch Center
2. **Level One** (more than normal, less that 6 hours) –
   - Dispatching from Central Dispatch Center with added resources
3. **Level Two** (more than 6 hours, less than 12 hours) –
   - Storm site mobilized for resource management
   - Dispatching continues from Central Dispatch Center with added resources
4. **Level Three** (more than 12 hours, less than 24 hours) –
   - Storm site mobilized for resource management
   - Nearest Regional Dispatch Site is mobilized for dispatch of the storm site.
5. **Level Four** (more than 24 hours) –
   - Storm site mobilized for resource management
   - Regional Dispatch site is mobilized for dispatch of the storm site or Storm Site assumes dispatching functions with resource assistance.

Once the storm center is activated, appropriate personnel are mobilized to staff the various command functions. The level of activation also provides triggers for resources, both in terms of materials and crews. Other key decisions in the mobilization timeline are when to secure line and crew contractor commitments, when to request mutual aid support from other utilities, and when to release resources.

8.1.6 Materials Management and Logistics

Materials management and logistics form the backbone of a utility's restoration effort. During the course of the event, the utility must ensure that personnel are properly fed, visiting crews have lodging, workers have access to materials and tools, trucks and other equipment are maintained and fueled, security is in place, transportation, water, ice and laundry and bathroom facilities are all available, and scores of other details without which work would grind to a screeching halt. One of the key findings over the years, as obvious as it sounds, is "*you can't work more people than you can logistically house and feed*."

8.2 During the Storm

8.2.1 Damage Assessment and Public Safety Processes

The time to restore a distribution system following a major event is highly dependent on a quick and accurate assessment of system damage. In terms of the process flow, this assessment follows staging and positioning (which should already be in motion before the storm), and should precede crew deployment and the performance of actual restoration activities.

Damage assessment scouts, also called field checkers, or spotters, evaluate storm damage before line crews are dispatched. Ideally assessors are personnel specifically selected for their knowledge of the system and geography, who have been put through a training program before the storm season. The role of a damage assessor is to patrol the feeders to identify trouble spots, evaluate the extent of the damage, and develop initial estimates of resources needed for restoration. The assessment generates critical information that helps to define the scope of the work, prioritize efforts and assign resources. Since this can be a bottleneck to the restoration process, a best practice is the use of processes and technology such as mobile communication and Smart Meters to efficiently collect and transfer damage data to the operations center.

The goal of the public safety process is to protect the public and make as many hazardous situations safe in the shortest possible time. The most common public safety hazard on overhead systems is from arcing or downed wires. Other public safety concerns include open neutrals from secondary damage, contact voltages from energized underground facilities, and flooded metering equipment. A leading practice among utilities is to have safety functions proceed in parallel with damage assessment.

8.2.2 Crew Deployment

Crews are dispatched to repair damage and restore service after the damage assessment data is analyzed to determine the best deployment strategy. This is not an exact science. Local personnel are typically deployed in their home regions. Mutual aid and contract personnel are deployed based on various strategies, but utilities strive for equitable deployment, so that no region is disadvantaged to benefit another. Some factors that go into making deployment decisions include:

- Proximity of area to incoming mutual aid crews
- Number of customers out
- Number of critical facilities damaged
- Severity or extent of damage
- Ease of repair or access to damaged areas
- Geography and customer density

- Logistical support available

Taking all these factors into consideration and making logical deployment decisions, still does not guarantee that there will be equitable restoration or that some customers will not feel that they were intentionally neglected.

8.2.3 Clearing, Repairing and Switching

Clearing lines, repairing damage and switching customers are core activities of the restoration process. Once damage assessment is complete, coordinators in the storm center have a fairly good idea of the size and extent of the damage and the resources required. Crews are then assigned (dispatched or deployed) to specific areas to restore the system. One of the best practices in use is to coordinate switching and clearance activities to achieve best maximum efficiency. There is a wide range of opinions as to what the proper balance is between allowing crews to work autonomously to speed up restoration, and controlling and coordinating crew activities to ensure safety and efficiency. Whenever a crew works on a circuit, they need clearance to lockout the circuit for repair, and switch it on when the repair is completed. All switching can be controlled from the operations center (centralized) or switching responsibility can be decentralized to the districts, substation areas, feeders, or even to the field crews. The manner in which clearances and switching requests are handled can have a huge impact on the overall effort. This can be facilitated (or hindered) by the technology (or lack thereof) in the field and operations center.

8.2.4 External Communications

External communications comprises of all contact outside of the utility, with customers, government officials, community leaders, the media, public safety organizations, other utilities and emergency management organizations. When the power goes out, customers typically what to know three things: Does the electric company know my power is out? When will the power be back on? What caused the outage? Failure to provide adequate information can lead to frustration, disillusionment and a dissatisfied, complaining customer. In particular, customers often express frustration when they cannot get an estimated time of restoration (ETR) or the time is so long as to be meaningless. The use of integrated technology to develop reasonable ETRs and communicate them to customers proactively via different media is essential.

8.2.5 Internal Communications

Internal communications is communications within the utility enterprise needed to manage and coordinate the storm response – one of those things that is often taken for granted and critically missed when it's gone. Poor or no internal communications can potentially hobble the entire effort. During a storm, many modes of communication are used to report emergencies, keep families and off-duty personnel up-to-date, maintain contact with customers and suppliers, and coordinate response actions. Typically the primary means of communication with crews and other responders are by two-way radios, cell phones, remote data terminals, and in some cases satellite phones. Not surprisingly, there is more reliance on private networks than on public or commercial services during emergencies, because experience has shown that private networks are more reliable during major storms.

8.2.6 Technology Use

There are many other applications and networks that are built on, and enabled by the core communication layers that have also become indispensable tools in outage response. As utilities realize their potential to improve efficiency and reduce cost, various applications are becoming a more common part of the storm restoration process. Some of the more common ones identified as being useful for storm response include interactive voice response units (IVR/VRU), outage management systems (OMS), automated meter reading and advanced metering infrastructure (AMR/AMI), mobile computing, geographic information systems (GIS), mobile workforce management (MWFM), work management systems (WMS) and automated vehicle location (AVL). The greatest potential, however, lies in the integration of these applications to seamlessly move data between the field, operations and back office.

8.3 After the Storm

When the intense activity and frenzy of actual restoration is nearing an end, a sense of accomplishment and finality may set in. But this could be misleading, because as every utility that has been through a major storm knows, there is still a tremendous amount of work to be done, and typically with fewer resources than during the actual system restoration. The post-event period can be broken into three phases: ramp-down, clean-up and review. During the ramp-down phase of post-storm recovery, resources must be demobilized in a rational, intelligent way to complete outstanding tasks and not incur unnecessary costs. Clean-up is one of the more underestimated activities of storm recovery. After storms that cause widespread damage, it is not uncommon for utilities to be cleaning up downed trees, broken limbs and debris, and making facilities repairs for months after actual system restoration. Every storm is unique and there are important lessons to be learned from each experience. The post-event phase provides the perfect opportunity for self-assessment, peer review and sharing of lessons-learned. Shortly after the storm, findings need to be assembled and documented for the benefit of future storm responses, for response to regulatory requests, and for public dissemination.

9 APPENDIX C: SG AND DA TECHNOLOGIES & PROGRAMS

9.1 Distribution Automation

Distribution Automation (DA) is one important subset of the Smart Grid technology suite that can have a range of expected benefits such as reliability, productivity, and efficiency, depending on the type of project and how it is implemented. DA includes both monitoring and control technologies on the distribution system between the substation and the meter, and may also be integrated with centralized operator software, such as a Distribution Management System (DMS). DA may also leverage shared investments with other SG activities, such as communications, and information systems involved in Advanced Metering Infrastructure (AMI).

Distribution Automation (DA) can play a major role in limiting the storm damage and speeding storm recovery. Utilization of various elements of DA in storm recovery requires planning for and implementing specific technologies based on carefully worked out coordinated system operations. Recently, under the umbrella of Smart Grid, the trend of DA deployment has moved towards real-time adjustment to changing loads, generation, and fault conditions on the distribution system, with minimal operator intervention.

Distribution Automation is not just a single product or application. It includes a range of solutions (as shown in the DA continuum in Figure 9-1 below) to optimize the level of automation needed to meet various challenges.

Within the DA sphere, there are different applications with various objectives. One set of applications is focused on reliability and includes deployment of automated feeder-level devices (sensors, switches, auto-reclosers, etc.), near real-time communications to these devices, and, in many cases, centralized control, by either a Supervisory Control and Data Acquisition (SCADA) system at the substation, or a Distribution Management System (DMS) at the operations center. In combination, these tools provide distribution feeder monitoring, outage detection, outage location, sectionalization, and automated service restoration, via remote system reconfiguration. They enable supply of power to customers by isolating the affected area around a fault and redirecting service from another adjacent circuit wherever possible to serve customers outside the immediate fault area.

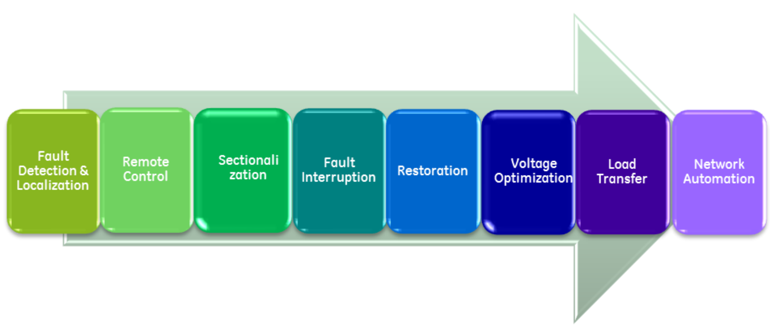

Figure 9-1 Distribution Automation Continuum

Other DA technologies include asset monitoring (such as Dissolved Gas Analysis on transformers) to provide remote diagnostics of asset health and enable condition-based maintenance, based on loading, age of equipment, or specific pre-failure indications. Predictive asset maintenance improves reliability, by reducing the likelihood of unplanned equipment failures. Asset monitoring primarily provides "blue sky" (or day-to-day) reliability benefits that are not necessarily correlated with storm activity or other major events, although they could provide additional information during such events.

A further set of applications of DA technology includes the various flavors of Volt/VAr control (dynamic control of active and/or reactive power along a feeder). These include Conservation Voltage Reduction (CVR), Integrated Volt-VAR Control (IVVC), Centralized Volt-VAR Control (CVVC), and Dynamic Voltage Optimization (DVO) or Volt-VAR Optimization (VVO).

In general, these applications are not targeted toward providing reliability benefits but aim to achieve greater overall system efficiency and peak load management, and facilitate the integration of distributed energy resources, such as photovoltaic (PV) generation. Again, these applications may be valuable for their primary intended purpose, but are not likely to contribute directly to storm resiliency.

At the most advanced end of the DA spectrum are closed-loop automation schemes, such as Fault Location, Isolation, and Restoration (FLISR), typically operated by a centralized software-based Distribution Management System (DMS). Such schemes reduce outage times by automatically detecting a fault, isolating the faulted area from the rest of the grid, and also automatically reconfiguring to restore service to remaining areas.

Weather events, such as hurricanes or winter storms, can challenge a utility's ability to restore power using DA. For instance, outages can be widespread and much of the grid infrastructure can be de-energized, reducing the options to restore un-faulted sections. However, remote supervision and control of the distribution system can significantly reduce the repair and restoration times, once the storm has subsided and a complete damage assessment made.

9.1.1 NSTAR Example

An example of a Northeast utility with substantial investment in DA is NSTAR, based in Boston. NSTAR's DA system communicates with remote operations and has auto-restoration capabilities with remote supervisory control of a multitude of overhead and underground switches. In 2011, during Irene, NSTAR had 506,000 total customer interruptions and 232,000 customers were restored in less than one hour.[1]

[1] Severe Weather and Distribution Grid Automation, http://www.nema.org/Storm-Disaster-Recovery/Smart-Grid-Solutions/Pages/Severe-Weather-and-Distribution-Grid-Automation.aspx

For outages during the first nine months of 2012, NSTAR reports that 71,000 customers avoided a sustained outage and 163,000 customers were restored within five minutes or less. In 2012, Superstorm Sandy impacted 400,000 customers and 274,000 customers were restored within the first 24 hours.[2]

Integrated distribution system models combined with advanced data analytics are an emerging technology, expected to be an essential component of a more intelligent power grid and enable operators to analyze on-going storm effects, as well as forecast damage possibilities, and then take action in real-time to perform switching and reconfigure their networks as the grid changes.

Key findings:

- "Self-healing" reliability-oriented SG-DA, including automated field devices and decentralized or centralized control, improves reliability by accelerating the detection and isolation of faults and reconfiguring automated switches to restore service quickly (wherever feasible).
- The benefits of DA to storm resiliency and recovery are harder to quantify (due to the lack of available metrics) but anecdotal evidence suggests they are real and potentially substantial.
- Advanced automation systems may not be able to operate autonomously during a major event, due to the chaotic nature of emergency operations. However, SG-DA will be extremely valuable to utility operators during extended storm recovery and restoration.

9.2 Integrated Communications

Electric utilities must incorporate technology to leverage information gained from external sources to improve their situational awareness, assess any damage to electrical infrastructure, and dispatch the appropriate resources to expedite power restoration efforts. Incorporating information from social media and emergency responders as well as telephone or cable providers can help assess the condition and operating status of physical assets.

Electric utilities can better manage information by training personnel to leverage automation technologies and processes to enhance situational awareness and optimize responses to evolving operating conditions during major storm events. Utilities, communities, states, and regions can all enhance storm response by integrating their Smart Grid technology with people and processes.

[2] NSTAR News Release, October 31, 2012, NSTAR Restores Power in the Wake of Sandy, http://www.nstar.com/ss3/nstar_news/press_releases/2012/NSTAR%20Sandy%20Restoration%20Update%2010-31.pdf

A White House report on the impact of Hurricane Katrina[3] highlighted the fact that the complete devastation of the communications infrastructure left emergency responders and citizens without a reliable network across which they could coordinate. A key lesson learned was that the communications challenges across the Gulf Coast region in Hurricane Katrina's wake were more a problem of basic operability, than one of equipment or system interoperability.

A key construct of Smart Grid is robust data collection and advanced information processing. Collection of data from a variety of sources and data analytics can be used to optimize grid operations in real-time and also provide grid operators with actionable intelligence concerning outage conditions, pending threats, vulnerable grid corridors, and external factors such as storm events or malicious actions. The communications infrastructure stands as the critical fabric enabling important data acquisition and communications operations. The communications infrastructure is a critical element of grid operations and should be hardened with a high level of resiliency. A comprehensive approach to development of integrated communication system would have the following features:

- **Redundancy**: Include protocols and network architectures that provide network redundancy to enable continued operation during extreme events.
- **Cyber-Security**: Incorporate a layered security architecture and intrusion detection services to prevent malicious tampering.
- **Planning & Testing**: Routinely test primary and backup systems that monitor and control key grid operations.
- **Cost reduction**: Many cost reductions can come from leveraging additional functionality to realize additional benefits. Plan to leverage the AMI/FAN/NAN/LAN/WAN communications networks for additional uses including automation functions and information backhaul.
- **Harden Key Control Points**: Increase communications resilience in zones that monitor key control points.
- **Mobile Communications:** Invest in systems to communicate with customers and mobile computer equipment for field personnel doing repairs and providing critical information when assessing damage and options for restoring service.
- **Harden AMI**: In many cases the AMI communications and data management infrastructure is primarily deployed to support interval meter reading and is not always designed with grid resilience in mind. Utilities that plan to take advantage of AMI data in emergency response will need to develop a higher level of resiliency.
- **Spatial Intelligence:** Integrate applications such as Google Earth with the utility GIS to visualize terrain in 2D and 3D models.
- **Social Media:** Leverage information from social media and emergency responders (e.g., smartphone video and GPS-tagged photo images submitted via social media). Customers with smart phones are able to receive updates from utilities, and in some cases, make utilities aware of trouble spots.

[3] http://georgewbush-whitehouse.archives.gov/reports/katrina-lessons-learned/chapter5.html

- **First Responder Integration/Coordination:** Enhance coordination and technology to enable police or other entities to share video surveillance to assist in accurately pinpointing outages.
- **External Information Sources:** Establish information links to enable cable TV and telephone companies to share information on outages identified through their systems.

It is important to ensure robust and uninterrupted communication in order to ensure timely dissemination of storm related information, efficient management of the recovery operations, and enable coordination and feedback among the recovery crew and the recovery operational centers.[4] The two communications domains are internal and external communication.

9.2.1 Internal Communication

Internal communication, between the utility control room and the field personnel, is critical in assessing the storm damage and prioritizing the options for the restoration of service. Advanced Communications networks, including wireless, mobile broadband, satellite communication, and "push-to-talk" radio (also known as "Press-to-Transmit" radio), provide seamless, uninterrupted and redundant channels for interactive communication between and among the utility's emergency/storm center and various field personnel and utility emergency responder teams. The communication network handles both voice and data communication, and should be cybersecurity enabled.

A Quanta Technology report for the Public Utility Commission of Texas identifies Satellite Communication and Global Positioning system (GPS) Tracking System as two technologies that could be valuable during storm recovery efforts.[5] Satellite communications are less susceptible to storm related disruptions, since they do not depend on terrestrial network structures that can be damaged, such as cellular and microwave towers and communication poles.

The Quanta report claims that employing satellite communications during the storm recovery effort could shorten the system restoration times by as much as five (5) to ten (10)% (relative to other communication systems).[6]

The GPS Tracking System enables locational information on the position of utility crews and equipment and a more efficient management of the recovery process via real time rerouting and deployment of restoration crews. The Quanta report claims that a Work Management System with integrated GPS Tracking System has the potential to result in a 20% reduction in restoration times.[7]

The Quanta report also recommends that during initial recovery effort, particular attention should be given to restoring any damaged Smart Grid related communications systems, since restored Smart Grid functionality can help with the overall restoration process.[8]

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[4] "Toward More Resilient Communications Networks", Official FCC Blog, David Turetsky, Chief of the Public Safety and Homeland Security Bureau October 28, 2013. http://www.fcc.gov/blog/toward-more-resilient-communications-networks

[5] "Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs", Prepared by Quanta Technology for the Public Utility Commission of Texas, March 4, 2009, Page 74.

[6] ibid

[7] ibid

[8] Ibid, Page 75.

9.2.2 External Communication

External communication during emergency conditions is essential for providing timely information to the public and other service providers, including emergency medical responders, local government agencies, fire fighters, and police. Utility customers need to be kept informed of planning for emergencies, utility preparation, status of power outages, and the estimated power restoration times. With the advent of new technology, customers expect their utility to make effective use of the Internet and mobile technology (smart phones/smart tablets) to communicate outage and restoration information. Use of smart communication would also enable customers to help utilities to locate trouble areas. Examples of communication avenues are:

- **Internet Based Social Media**: to reach a wide social media audience tracking storm related information.

  Some utilities are using social media to better understand the location of a problem and to communicate with customers. During Superstorm Sandy a number of utility companies used Twitter, Facebook, and other websites extensively to relay information, evacuation orders, and updates.[9]

- **Utility Storm Central Portal:** to provide centralized information bulletin board on the storm conditions and the status of outages and estimated restoration times to anyone with internet access (see Table 3-1 for a comparison of NJ EDC storm portals). For instance, during Superstorm Sandy, NSTAR, National Grid, Unitil, and WMECO provided to up-to-date outage maps on their website.[10]
  - Automatic Customer Text/Voice Messaging: to automatically send short text/voice messages to the utility customers with relevant storm related information.
  - Interactive Voice Response/Voice Response Unit (IVR/VRU) technology to queue, prioritize, and route automated calls to customers.
  - IVR/VRU should be coordinated with Customer Information System (CIS) so that it can associate a caller with a billing account.
  - IVR/VRU should be integrated with the OMS so calls show up in the OMS as soon as the caller is identified by the IVR. To close the loop, agents in the call center should also have access to the OMS and CIS data, to give the customer relevant information.
  - Ensure that an adequate number of phone lines and queue capacity are in place to manage the high call volume imposed by major storms.
  - Make first IVR option during storms, "report an outage," not billing inquiries, etc.

- Improved Callout System: Use of mobile technology and improved system procedures for emergency call-out systems that summon appropriately authorized and trained personnel to respond to and deal with outage reports during a storm emergency. The Callout System can also serve as a mass communication tool that allows users to instantly communicate critical, predefined messages to large groups of people.

The advent of smart phone technology and widespread access to mobile communication and the internet has enabled social media and collaborative technologies to become components of

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[9] "Lessons Learned: Social Media and Hurricane Sandy Virtual Social Media Working Group and DHS First Responders Group", US Department of Homeland Security, Science of Technology, June 2013, Page 17.

[10] http://www.wbur.org/2012/10/29/massachusetts-storm-sandy-updates

emergency preparedness, response, and recovery. For instance, social media was heavily relied on for sharing of information and providing notices regarding community actions, and mobilizing clean-up actions during Sandy.[11]

To address challenges in adopting social media technologies by various agencies during major emergencies, the U.S. Department of Homeland Security's Science and Technology Directorate (DHS S&T) has established a Virtual Social Media Working Group (VSMWG), with the mission to provide guidance and best practices to the emergency preparedness and response community on the safe and sustainable use of social media technologies before, during, and after emergencies.[12 & 13]

A presentation by CenterPoint Energy subsidiary Houston Electric describes its emergency operations and post hurricane social media plan based on lessons learned from Hurricane Ike of September 2008.[14]

The same presentation summarizes the best practices (or lessons learned) based on its utility peers' experience (i.e., BG&E, PSEG, PEPCO, and National Grid) with Hurricane Sandy:

- Be proactive: start messaging as soon as a forecast is clear
- Offer visual evidence of work through photos and video
- Use a storytelling approach, treat the story as a news story with the utility as a reporter
- Post frequently
- Engage influencers (media, public officials)
- Give credit to mutual assistance crews, makes the story viral across the country

[11] "Hurricane Sandy's social media clean-up efforts help New York, New Jersey recovery", The Washington Post, November 20, 2012. http://www.washingtonpost.com/national/hurricane-sandys-social-media-clean-up-efforts-help-new-york-new-jersey-recovery/2012/11/20/32dddaf0-3029-11e2-ac4a-33b8b41fb531_story.html

[12] "Next Steps: Social Media for Emergency Response - Virtual Social Media Working Group and DHS First Responders Group", U.S. Department of Homeland Security, Science and Technology Directorate, January 2012.

[13] "Lessons Learned: Social Media and Hurricane Sandy Virtual Social Media Working Group and DHS First Responders Group", U.S. Department of Homeland Security, Science and Technology Directorate, June 2013.

[14] CenterPoint Energy Houston Electric, Competitive Retailer Workshop, April 30, 2014. http://www.centerpointenergy.com/staticfiles/CNP/Common/SiteAssets/doc/PostHurricaneSocialMediaCommunications2014CRWorkshop.pdf

Key findings:

- Robust, uninterrupted communications are vital to storm restoration efforts. Utility plans should address both internal communications (between control centers and field crews), as well as external communications with customers and other key stakeholders, and ensure redundancy and cybersecurity of critical communications infrastructure.
- An example of an emerging technology for internal communications is satellite or GPS tracking of field crews integrated with WMS, which gives the utility operator real time situational awareness and allows efficient dispatching and rerouting of crews.
- Mobile social media technology is increasingly becoming an important ingredient of utility external communications activities. During a storm, customers can receive and communicate important updates with the utility via smart phones when other, more traditional communications may be unavailable (because customers are displaced or landline service is disrupted).

9.3 Monitoring, Sensing, and Control Technologies

Advanced sensors, multi-source data collection, data analytics, spatial visualization, and storm and emergency response simulation are all Smart Grid technologies and systems that can enhance situational awareness and improve storm response. The key benefits are the ability to increase real-time situational awareness, enhance crew safety in the field, optimize and speed decision making, and reduce time to restore power.

Situational awareness refers to the ability of the control room operator to know what is happening on the grid and to anticipate future problems in order to take effective action. Enhancing situational awareness will help operators better anticipate and recover from severe storms. There are two primary components to situational awareness: grid visibility and analytic tools that support decision making.

Today, transmission and distribution operators track what is happening on the grid through sensors or by receiving phone calls from customers. Installing additional sensor types will enhance operator visibility into the grid and enable operators to rely less on customer calls or field crews during storm events. Sensors provide accurate real-time alerts directly from remote field devices connected via a hardened communications infrastructure.

9.3.1 Advanced Sensors

- **Phasor Measurement Units (PMUs).**

  PMU's are one type of new, high precision sensor. PMUs measure current and voltage on the grid 30 times per second, which is much more frequent than legacy sensors presently installed.

  Placement of PMUs at strategic locations across the power delivery system can significantly enhance the operator's ability to monitor grid stability. PMU Networks across multiple grid regions can be interconnected to create broader situational awareness. PMU networks can provide enhanced wide-area visibility to improve resiliency by enabling grid operators to track pending threats and better understand vulnerabilities in their region.[15]

- **Advanced Transformer Monitoring:** Transformers with remote-monitoring sensors can provide operators with a near real-time readout of loading, temperature, pressure, and oil level.

  If any parameter exceeds operating limits, crews can be dispatched quickly to check the transformer, correct any problems, or even remove the unit from service if necessary. An operator can also remotely switch off the transformer. Remote-monitoring capability may improve overall system resiliency and may facilitate pre-emptive asset maintenance to avoid having weak components in an area vulnerable to storm events.[16]

- **Fault Sensors:**

  Most intelligent feeder-level DA devices, such as smart relays and switches continuously measure current and voltage characteristics and provide fault detection and notification back to SCADA or a DMS when abnormal conditions are detected.

- **Smart Meter and AMI Capabilities**:

  Installing advanced meters at residential and commercial customer sites can provide two-way communication so that operators will know which customers have service in real time. Fully leveraged Smart Meter and AMI capabilities capture outage intelligence, ascertain service status, monitor performance data, and integrate AMI data with other utility systems.

- **Aerial Data Acquisition:**

  Leverage data acquisition technology and partners to perform damage assessment using remote cameras and UAV's.[17]

- **Integrate Data Collection:**

  Information captured from multiple sources during storm events can be analyzed to optimize resource allocation and timing when dispatching to repair faults.

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[15] http://www.nema.org/Storm-Disaster-Recovery/Wire-and-Cable-and-Components/Pages/Submersible-Transformers-and-Switches-Advanced-Monitoring-and-Control.aspx

[16] ibid

[17] "Post Storm Data Acquisition - Aerial Wind Mapping Mission - Hurricane Ivan – 2004", U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA). http://www.nws.noaa.gov/om/data/pdfs/IvanPSDA.pdf

Distribution (or Distribution Feeder) Supervisory Control and Data Acquisition (D-SCADA or DSCADA) systems are used to monitor the status of the distribution system and interact with automated and intelligent distribution field devices. D-SCADA is primarily used to operate DA schemes with decentralized, device level control logic. DMS (and its integration with OMS) provides the platform for centralized, software-based control schemes, such as Fault Location, Isolation, and Service Restoration (FLISR).

Connecticut Light & Power (CL&P) and Public Service of New Hampshire are examples of utilities with operational D-SCADA systems.[18]

D-SCADA may include a combination of various subsystems, including:

- Analytics System
- Data Acquisition and Data Management Systems
- Programmable Logic Controllers (PLC)
- Remote Terminal Units (RTU)
- Sensors
- Telemetry and Communications Infrastructure
- User Interface

Advanced D-SCADA systems provide continuous information on various aspects of the grid and are one solution for real-time situational awareness of the overall grid. Advanced D-SCADA systems include hardware and software disaster recovery plans.[19]

Advanced D-SCADA systems can be part of Integrated Distribution Management Systems (IDMS), which combines D-SCADA, DMS and OMS on a single IT platform.

> *"IDMS provides real-time situational awareness of the electric grid and customer outages, and is accessible by field personnel during the restoration process. IDMS integration with smart meters via automated metering infrastructure (AMI) provides control room operators with real-time information on outages rather than waiting for customers to call in. The ability to connect with these meters from the control room enables operators to check for service restoration and power quality, and notify customers via phone, email, or social media."*[20]

[18] http://www.smartgridupdate.com/distributionautomation/pdf/Camilo-Serna.pdf
[19] http://www.riversideca.gov/pworks/pdf/masterplan-wastewater/Vol%206%20-%20CH%2001%20-%20SCADA%20Management%20Plan.pdf
[20] http://www.nema.org/Storm-Disaster-Recovery/Smart-Grid-Solutions/Pages/Preparing-and-Restoring-Power-Grids-Using-Smart-Grid-Technologies.aspx

Key findings:

- Digital sensors and measurement devices, such as PMUs, transformer monitors, remote fault sensors, and AMI smart meters all help to provide additional situational awareness to the utility operator.
- During storm operations and post-storm recovery, increased situational awareness provides faster detection of fault conditions to allow utility operators to respond more rapidly – both through automation and dispatch of field crews. ,
- D-SCADA or Integrated OMS/DMS are emerging technologies that provide the operator interface for monitoring remote sensors, as well as the control fabric for communication with switching devices on the distribution system.

9.4 Advanced Asset and Work Management System (WMS) Technologies

A critical aspect of the utility response during emergencies and storm events is keeping track of the status of the work crew and utility equipment. Utilities use various tools and technologies mentioned in the reviewed documents, including:

- **Advanced Work Management Systems (WMS) / Advanced Field Crew Management Systems**, are used for work order processing and management, resource assignment, job status and completion tracking, for example, the Consolidated Edison plan described in its 2013 rate filings for an Electric Operations Work Management System deployment, to be fully implemented in September 2014.[21]

The filing sates that the Consolidated Edison's work management system platform will provide:[22]

- A single repository for all planned and emergent work within Electric Operations so users no longer need to access multiple systems to process work
- An interface that provides detailed information about electric distribution assets for which work is being performed
- A comprehensive facility that helps manage all maintenance and inspection programs
- A mechanism to match project work requirements and tasks to worker skills and other resources such as vehicles and other equipment
- Trending and analysis of workforce and equipment performance
- A summary of all associated costs by work activity or project

[21] Consolidated Edison, 2013 Rate Filings, Electric Infrastructure And Operations Panel, Page 85. http://www.coned.com/documents/2013-rate-filings/Electric/Testimony/09-ElectricInfrastructureandOperationsTestimony-Final.pdf

[22] Ibid, Page 91.

- Interfaces to Finance, Supply Chain and HR systems that reduce clerical input and further streamlines processes
- A resource scheduling and planning assistant
- Integration with mobile technologies allowing transmission of data to/from the field

Upon full implementation, the Company expects to realize annual savings of $45 million dollars, split between capital and O&M.

- **Improved and Automated Callout Process and Roster Management System**, to streamline the callout process together with appropriate technology for reporting of emergency conditions and to communicate the request for reporting of personnel to deal with the emergency.
  - For example, Callout and Scheduling Suites that find, assemble, and track repair crews while they perform service restoration and emergency and storm response for utilities.
  - For instance, Lakeland Electric's "Callout" system has improved the process of calling out crews in emergencies has resulted in faster response time and improved reliability.[23]
- **Integrated AMS/GIS/WMS systems**

These can capture up-to-date facility information from the utility's Asset Management System (AMS) and Geographic Information System (GIS) on the front end of the work-order process, and provide the necessary work orders, ensuring crews' work orders reflect the current system, and reflect the current system state as repairs progress.

- For example, Dakota Electric Association determined that all work done outside of the main office must be done via a single GIS-based Work Management System (WMS).
- The Association's System Control was able to use their GIS/WMS system effectively during a major storm on June 19, 2012 which passed through Dakota Electric's service territory at 4 AM, knocking out power to 20% of the utility's customers.
- By 10 a.m., all but a few hundred customers had their power restored, and by midnight, all power was restored. All the storm related restoration was managed and coordinated electronically without any paper.[24]

An example of combined AMS and GIS is the Automated Mapping and Facilities Management (AM/FM) feature which involves automated geographic location mapping of the utility assets and facilities, resulting in more efficient management of those facilities. An example is Entergy's Texas service territory, which after Hurricane Rita, upgraded the AM/FM system used in its Distribution Operations Center25, for which it won second place in the distribution category at the Southeastern Electric Exchange Industry Excellence 2003 Awards Program.

[23] Relay Magazine, March 24, 2014. http://relaymagazine.org/calling-faster-way-get-lights/

[24] "Can GIS be doing more for my utility?" ESRI News for Electric & Gas Utilities Fall 2012, Pages 1 & 2. https://www.powereng.com/wp-content/uploads/2012/08/Esri_News_GIS_for_My_Utility.pdf?term=geospatial-asset-management

[25] "Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons Infrastructure Security and Energy Restoration", Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, OE/ISER Final Report, August 2010, Page 54.

The AM/FM system replaced the problem-plagued process of using multiple manual and computerized systems to organize and gather distribution data.26

- **Automated Vehicle Location (AVL)** is an example of an Asset Management System that provides real-time information on utility vehicle locations. For instance, the City of Raleigh has issued a Request for Professional Services for implementation of a Global Positioning System/Automatic Vehicle Locator (GPS/AVL) tracking system solution for the City of Raleigh Public Utilities Department (CORPUD).[27]

Such systems can be integrated into the storm recovery and restoration plans for efficient allocation and utilization of crew and equipment resources during emergency and storm events. They could also be helpful in integrating "mutual aid" resources borrowed from other utilities.

Key findings:

- AMS and WMS technologies provide tracking of the availability of utility field crews and their operational assets (e.g., trucks and tools), ensuring that the right resources are available where and when they are needed.
- Emerging technologies in this area that can be particularly beneficial in storm response include advanced Roster Management/Callout Processes for efficient crew mobilization; integration of WMS with AM/FM GIS to allow geographic location of assets (e.g., where is the nearest spare part in inventory?); and Automated Vehicle Location.

9.5 Geospatial Information Systems and Advanced Mapping Technologies

Geospatial (or Geographic) Information Systems (GIS), Advanced Mapping Technologies, and GPS-enabled technology can aid in conducting a post-storm facilities survey to locate and document damage, the need for repairs, and new equipment and configurations; and to upload data to a central database. GIS mapping, delivered through a user friendly interface and remotely through truck-board computers or other mobile devices for field crews, can help organize and coordinate recovery efforts and speed up utility storm response by rapid delivery of information such as the locations of outages, flooded zones, or travel hazards to utility personnel. GIS is also integrated with WMS to aid field crews in locating and scheduling the use of resources, such as trucks, tools, and equipment that will be required for a specific repair.

After Hurricane Isabel, Dominion developed an application called Hazard Patrol (built on ESRI's GIS suite) to collect and report hazard locations to the office. The application was successfully used in their post-storm survey/inspection to identify over 23,000 hazard locations, and even helped

[26] http://www.entergy.com/about_entergy/awards.aspx

[27] City of Raleigh, Public Utilities Department, Request for Professional Services, Project: Global Positioning System/ Automatic vehicle location, Project Manager: Michele Mallette, Date of Advertisement: June 18, 2014.

recover several hundred thousand dollars from the ability to track non-Dominion owned joint-use poles that were replaced during restoration.[28]

On November 17, 2011, the Connecticut GIS Council established a "Storm Response and Recovery Assessment Group" to review the use (or lack of use) of GIS Technology during Tropical Storm Irene (August 2011) and the October Nor'easter (October 2011). The Assessment Group focused on various aspects of how GIS was used for pre-storm, storm, and post-storm response and recovery efforts at the local, regional, utility, state, and federal levels.

The goals of the assessment was to identify what GIS strategies were used (or not), barriers encountered, best practices, and recommendations. The assessment was based on detailed responses by Connecticut municipalities and six utilities to a detailed survey questionnaire.[29 & 30]

The survey questioner included three parts (reproduced here verbatim):

> ***PART I:*** *Did your Emergency Operations Center (EOC) engage GIS resources? Explain.*
>
> ***PART II:*** *Describe how GIS was used for each applicable phase of the storm(s). Include details on maps and technologies used (printed maps, software, applications, etc.), in addition to barriers to success. Barriers can pertain to data, staffing issues, communication, software, technological limitation, etc. Please attach any map products as applicable. Describe:*
>
> a. *1. GIS Actions or Activities*
> b. *2. Barriers*
> c. *3. Other activities for the following:*
>   1. *Pre-storm*
>   2. *During the Storm*
>   3. *Post-Storm*
>
> ***PART III:***
>
> a. *List your "Best Practices" that helped in the storm response and/or recovery efforts*
> b. *List any Recommendations on how GIS can/should be used during a local, regional, or statewide disaster*
> c. *Other comments*

Survey results provide a useful list of (a) barriers to GIS use, and (b) best practices of GIS use, and (c) recommendations. The main issues identified are lack of staff, bureaucratic barriers, vertical and

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[28] "Extending GIS to the Field for Storm Damage Assessment", Jerry Warren, Dominion Resource Services, ESRI Electric and Gas GIS Conference, October 10-14, 2004. http://gis.esri.com/library/userconf/egug2004/presentations/extending-gis-to-the-field.pdf

[29] Connecticut Geospatial Information Systems Council Storm Response and Recovery Assessment Group Draft Findings Report, January 25, 2012. http://www.ct.gov/gis/lib/gis/Final_Draft_GIS_Storm_Assessment_Findings_Report_01_25_12.pdf

[30] "Connecticut Geospatial Information Systems Council Storm Response and Recovery Assessment Group Findings Report", Rhode Island GIS User Group August 14, 2012. http://www.edc.uri.edu/rigis/about/usergroup/20120814/20120816-JBolton-FINAL_Findings_Report_Rhode%20Island%20U2U_Group_Presentation_081412.pdf

horizontal organizational data sharing, and lack of tools for coordinated communication between different entities.

In New Jersey, the NJ Department of Environmental Protection's GIS[31] played a significant role in the response to Hurricane Sandy and the state's recovery.

The GIS team developed and provided a number of maps in real time which illustrated the following:

- Predicting rise in flood waters
- Census populations by block to show the most densely populated areas that would be affected by the surge and that might need to be evacuated first.
- Storm surge maps for Newark Bay
- A map depicting a levee break
- A map of statewide reconnection priority sites for the Board of Public Utilities

These locations were determined by the DEP and BPU to be prioritized when electrical grids were re-energized due to their importance for wastewater management and overall human health. Some of these locations included various municipal utility authorities or MUA's and treatment plants throughout the State.

- A map book for the Commissioner to use during a helicopter flight to assess affected areas from Sandy Hook south along the coastline, to the nuclear power plant in Salem.
- New data generated from a database query showing Solid Waste Facilities and Recycling centers that may be affected by Hurricane Sandy storm surge.

GIS and Advanced Mapping Technologies, including Automated Mapping & Facilities Management (AM/FM), can also incorporate information from Smart Meters and mobile data, in order to provide multiple layers of geospatial information to the utility personnel. AM/FM technology has actually been used by utilities for at least a couple of decades.[32]

Key findings:

- GIS and mapping technologies play a role in each phase of storm prediction, response, and recovery.
- Emerging technology applications include the geo-tagging of hazards during the post-storm damage assessment and the integration of AMI and mobile data with GIS (for example, identifying a piece of damaged equipment from a customer report, using either a meter location and/or a smart phone photograph of the damage).

[31] "Hurricane Sandy: NJDEP GIS Response and Recovery", NJ Department of Environmental Protection's Geographic Information Systems Website
http://www.state.nj.us/dep/gis/gisemerresp.html

[32] "AM/FM/GIS Moves to the Web", T&D World Magazine, Robert R. Johnston, Oct 1, 2001.
http://tdworld.com/archive/amfmgis-moves-web

9.6 Weather Tracking, Grid Analytics, and Storm Damage Prediction

9.6.1 Integrated Weather Tracking

Advanced knowledge in the pre-storm buildup phase can help in organizing storm recovery efforts. The level of predictability depends on the storm type. Some weather events, such as tornadoes and lightning have very short lead-times, while others such as hurricanes afford a much longer lead time for planning and preparation. Still other weather systems, such as snowstorms and ice storms, fall somewhere in between.

Utilities can access the National Oceanic and Atmospheric Administration (NOAA) National Weather Service data (through internet, radio, wire service, data feeds), or other public news, media, and internet sources, or obtain weather data through subscription to private and commercial meteorological services.

Although a steady progression in the application of weather data has been occurring for decades, with a trend toward more site-specific forecasts with more detail and longer lead times, the impact on utility storm operation will depend on how such applications are integrated into the utility's response plan and how the information is interpreted and the data utilized in real time. An integrated system will combine:

- Weather Monitoring and Forecasting
- Early Warning and Tracking System
- Computerized Storm Models
- Mobile Computing
- Predictive Analytics

9.6.2 Utility Data Analytics

In addition to enhanced visibility, transmission and distribution operators need the tools to interpret data, anticipate events, and recommend the most effective actions to implement. Utilities have implemented a variety of analytic tools for decision support to aid storm resiliency.

- **Arbor Intelligence:** Data analytics applied to vegetation management (VM) incorporates use of Radar and Lidar (Stands for "Light Radar") remote sensing to assess vegetation and tree growth patterns and support preventative vegetation management. This can provide early warning of what trees to trim and in what areas to focus use of vegetation management budget by pinpointing high risk and problem zones.[33] See discussion in Section 3.1.4 for more on analytics applied to VM.

[33] http://lidarradar.jpl.nasa.gov/

- **Grid Stability Analytics:** Feeding PMU data directly into the Energy Management System (EMS) will enable advanced visualization displays and analytical tools that provide operators with greater visibility of power flow, frequency and voltages in real time.[34]
- **Meter Analytics:** Leverage AMI and meter analytics to detect or verify customer outages. This helps reduce the time to respond to an outage and improves the ability to detect a nested outage, where a downstream outage can be hidden inside a larger primary outage upstream.[35]
- **Storm Outage Prediction System:** Prior to when a storm first impacts a region, the system can collect data from multiple sensors, external sources such as weather feeds, and historical storm data then apply analytics to forecast the total number of impacted customers and likely locations of damage to utility equipment. This forecast is valuable for mobilizing resources for storm recovery and is expected to result in quicker, more efficient restoration.[36]
- **Decision Support Tools:** Decision support systems include system models and simulation tools that enable contingency analysis, risk analysis, and modeling of system operations across hypothesized emergency scenarios and storm effects. This allows operators to discover and analyze system vulnerabilities, critical points of failure, and assess recovery timelines and modes within the context of an emergency scenario. Integration with business information systems, integrated distribution system models, and historical data can provide a highly robust scenario analysis platform.

9.6.3 Storm Damage Prediction

Complementing the weather tracking task is the storm damage prediction, which can help the utility to properly prepare its storm recovery action plans. A model-based storm damage prediction can be used to forecast the amount of damage a storm will produce, the resources required for restoration and the approximate time to restore service. Weather forecasts from an Integrated Weather Tracking system (such as peak wind speed, frequency and intensity of lightning, ice accumulation, etc.) would feed into the Storm Damage Prediction system, and in close to real time, provide the triggers for levels of storm center activation and crew mobilization as an essential part of the storm management process. The process will include:

- Damage Prediction
- Activation and Mobilization
- Staging and Positioning
- Damage Assessment
- Restoration Management

An example of a sophisticated damage prediction approach is the proprietary storm model used by Florida Power and Light (FPL).[37] FPL developed its storm model to forecast the type and extent of

[34] http://www.alstom.com/press-centre/2014/8/alstom-and-pge-to-advance-synchrophasor-grid-monitoring-into-proactive-grid-stability-management/
[35] http://www.oracle.com/us/industries/utilities/utilities-meter-data-analytics-ds-1624126.pdf
[36] http://www.bnl.gov/wius2013/talks/pdf/CScirbona.pdf
[37] http://www.investor.fplgroup.com/phoenix.zhtml?c=88486&p=irol-newsArticle_print&ID=720931&highlight=

damage after the storm Wilma.[38] Instead of a simple matrix or table, the model uses a damage curve to match wind speed with the estimated infrastructure damage.

The Storm Damage Forecasting Tool was tested on FPL's system during Hurricane Wilma in 2005. The following chart shows a comparison of actual customer outages by FPL regions and outage predictions made 24 hours before Wilma's landfall.

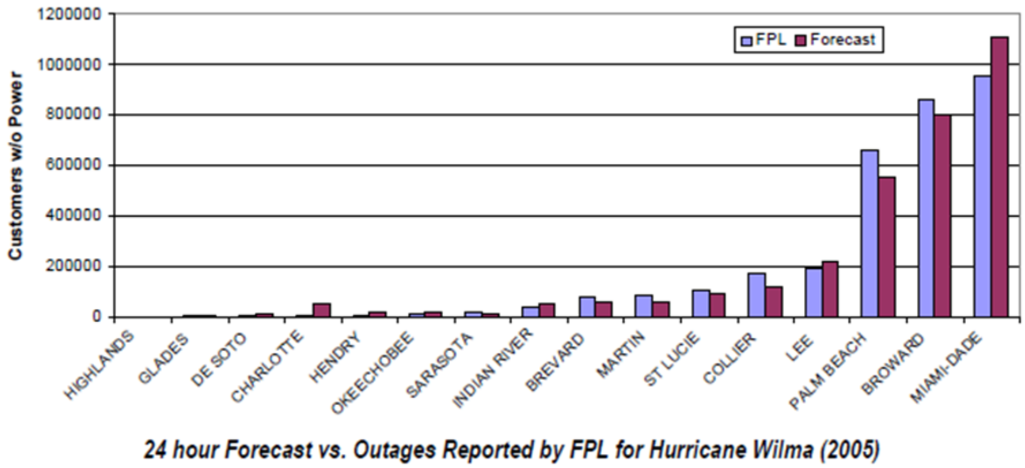

Figure 9-2 FPL Example of Testing a Storm Damage Forecasting Tool

Progress Energy, Southern Company, Entergy and a number of other large utilities with hurricane exposure have also developed in-house models to predict storm damage. Progress Energy Carolinas has adapted their model for use in winter storms.

A case in point is CenterPoint Energy, based in Houston. As Hurricane Ike approached the Texas coast, "using GIS-based damage prediction models, CenterPoint approximated how many customers would lose power, what the infrastructure damage would be, and how quickly repairs could be made. As the hurricane churned its way toward Texas, CenterPoint placed a supply order based on predicted damages so crews would be fully stocked and ready to make repairs once the storm subsided.

Since the damage model warned that Galveston Island would soon be under water, CenterPoint pulled supplies from the area and relocated crews. After the storm, they used GIS to create maps of damaged areas and share the information with customers, media, government, and support agencies."[39]

An example of a Northeast utility using its Integrated System Model to develop a storm outage prediction system is Orange & Rockland (O&R) in New York State. The system enables O&R to collect data from a number of sources prior to and when a storm first impacts their region, and forecast

[38] http://www.fpl.com/news/2005/contents/05161.shtml

[39] "Utility Praised for Quick Response, Restoration after Hurricane Ike CenterPoint Energy Earns ESRI Enterprise Application Award", Redlands, CA (PRWEB) August 4, 2009. http://www.prweb.com/releases/centerpoint/ike/prweb2712974.htm

the total number of impacted customers. This forecast will be used to mobilize storm recovery resources in order to result in quicker restoration of service.[40]

Computer storm models take into account additional variables that more simple approaches cannot accommodate. These can include electrical system topology, system design and layout, customer density and vegetation. Also, they draw from a more extensive history of weather conditions and storm damage. Consequently, computer storm models may offer more accurate and localized estimates of damage and restoration times.

One of the key GE recommendations is that BPU require EDCs to quantify potential improvement in damage forecasts by storm tracking and damage prediction tools, and assess resulting improvement in storm response. This recommendation is described in Section 6.4 (see SG-DA Recommendation SG-4).

Key findings:

- Model based storm damage prediction systems take weather tracking data and combine it with detailed electrical system data to create a highly detailed and accurate damage prediction model for different storm types.
- Accurate storm damage prediction allows for better utility planning, for example, allocating, pre-positioning and mobilizing storm response resources in the right locations to respond to likely trouble spots.

9.7 Distributed Energy Resources and Microgrid Applications

Recent severe weather events have motivated a number of Northeast states to develop policies that position Distributed Generation (DG) (including backup generators) and microgrids as a central element in ensuring operation of critical facilities and provision of essential services during major power disruptions.

An important aspect of the current U.S. regulatory framework and traditional utility business model is that electric utilities in the U.S. typically do not own and operate DG on their system[41], or sell DG to customers, or install and maintain DG at customer sites.

[40] "Powering New York State's Future Electricity Delivery System: Grid Modernization", prepared by the New York State Smart Grid Consortium, January 2013. http://nyssmartgrid.com/wpcontent/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

[41] See Section 4.2 for a discussion of back-up generation at the EDC owned facilities.

In fact, a main concern of the electric distribution companies in the U.S. with regards to the expected negative impacts on the distribution system reliability due to uncontrolled customer generation and also spiraling loss of customers, stranded distribution assets, and resulting revenue shortfalls (the so-called "utility-death-spiral"[42]).

Under the traditional regulatory framework and utility business model, there are many non-financial barriers to utility investment in DG and microgrids at customer sites. Additional policy changes may be needed to allow utilities to implement DG and microgrid resiliency strategies.

The following subsections discuss the role of DG, DER, and microgrids in storm recovery and grid resiliency. They are not meant to be viewed as a full discourse on the underlying technology of DG, DER and microgrids.

9.7.1 Distributed Generation (DG)

DG technologies include:

- Industrial Gas Turbines
- Reciprocating (Internal Combustion) Engines
- Micro-turbines
- Combined Heat & Power (CHP)
- Fuel Cells
- Biomass/Bio-power
- Solar Energy
- Photovoltaic Solar
- Concentrated Solar
- Wind Turbines
- Small Hydro

DER systems can also be based on hybrid technologies, such as Wind Power + Diesel Generation, or Photovoltaic Power + Battery Storage, or Fuel Cell Generation + Micro-turbine Generation.

A particular type of DG, namely Combined Heat and Power (CHP), in addition to being mostly an economically viable power and heat resource, appears to also be uniquely well suited as a useful resource during major storm events.

The use of CHP systems for critical facilities can improve overall grid resiliency and reliability and offers a less costly solution then deploying a formal microgrid structure. CHP offers the opportunity to improve resiliency, mitigating the impacts of an emergency by keeping critical facilities running without any interruption in electric or thermal service. If the electricity grid is impaired, a specially

[42] "Fireside Chat: Tomorrow's Utility in the Age of Distributed Generation", Greentech Grid, Eric Wesoff, December 11, 2013. http://www.greentechmedia.com/articles/read/Fireside-Chat-Tomorrows-Utility-in-the-Age-of-Distributed-Generation

configured CHP system can continue to operate, ensuring an uninterrupted supply of power and heating or cooling to a facility used for emergency refuge or medical care.

- **Improve resiliency by removing significant electrical load from key areas of the grid**. This is possible when CHP is installed in areas where the local electricity distribution network is constrained or where load pockets exist. The use of CHP in these areas eases constraints by reducing load on the grid. For this reason, CHP placement can be coordinated with the utility; this allows CHP design to be based on the conditions and needs of the host facility, but also on the conditions and needs of the local grid system. Both facility- and grid-level assessments should be part of the cost/benefit analysis for any proposed CHP system at critical infrastructure facilities.
- **Surety:** In general, a CHP system that runs consistently throughout the year is more reliable in an emergency than a backup generator system that only runs during emergencies. Because it is relied upon daily for needed energy services, a CHP system is more likely to be properly maintained, operated by trained staff, and to have a steady supply of fuel.

A recent example is the CHP system installed at New York University[43] which provided power and heat/hot water when much of Manhattan south of Midtown was blacked out during Hurricane Sandy[44], even while a backup generator at N.Y.U. Langone Medical Center failed during the same storm event.

A report presented to the President of the United States in the aftermath of Hurricane Sandy lists a number of CHP installations that provided uninterrupted power and heat before, during, and after the storm[45]. These included:

- College campuses such as Princeton University, Stony Brook University, New York University, and the College of New Jersey, used CHP to keep the lights (and the heat) on both during the storm and in the days and weeks that followed.
- South Oaks Hospital on Long Island and Connecticut's Danbury Hospital used CHP to keep medical facilities online when the local electrical grids failed.
- Commercial buildings and even residential communities like Co-op City in Bronx County, N.Y. showed the resilience benefits of CHP during Sandy.

An ICF International report prepared for Oak Ridge National Laboratory[46] summarizes how some Critical Infrastructure (CI) facilities with DG/CHP systems operated during Hurricane Sandy. The ICF report includes case studies on 14 sites (one in California, two in Connecticut, one in Louisiana, five in New Jersey, and five in New York). The New Jersey sites include the following:

- Christian Health Care Center - Wyckoff, NJ, 260 kW Micro-turbine
- Princeton University - Princeton, NJ, 15 MW Gas Turbine

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[43] "In New N.Y.U. Plant, a Collateral Carbon Benefit", New York Times Green Blog, Matthew L. Wald, January 21, 2011.
[44] "How N.Y.U. Stayed (Partly) Warm and Lighted", New York Times Green Blog, Matthew L. Wald, November 5, 2012.
[45] "Hurricane Sandy Rebuilding Strategy", Hurricane Sandy Rebuilding Task Force, Presented to the President of the United States, August 2013, Page 66.
[46] "Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities", ICF, Prepared for: Oak Ridge National Laboratory, March 2013.

- The College of New Jersey - Ewing, NJ, 5.2 MW Gas Turbine
- Salem Community College - Carney's Point, NJ, 300 kW Micro-turbine
- Bergen County Utilities Wastewater Plant – Little Ferry, NJ, 2.8 MW Reciprocating Engine

The DG/CHP at all five sites in New Jersey were able to continue operations during Hurricane Sandy, with the exception of some momentary blackouts.

The same report also summarizes a few state policies that promote CHP in CI facilities[47]. The two states identified in the Northeast with statewide incentives and funding for CHP projects are New York and New Jersey.

An important aspect of the New York program is the government funding of investments made towards clean energy projects - specifically those aimed at providing continuous power and heat during power outages. In fact, the program, which is administered by the New York State Energy Research and Development Authority (NYSERDA), will only fund those CHP systems that can continue operations during grid outages.[48]

New Jersey is also attempting to improve its energy resilience through adoption of CHP. The 2011 New Jersey Energy Master Plan states that "The Christie Administration is committed to developing 1,500 MW of new DG and CHP resources where net economic and environmental benefits can be demonstrated".[49] A solicitation for a large scale CHP-Fuel Cells program was issued by The New Jersey Economic Development Authority and The New Jersey Board of Public Utilities on January 17, 2013, which made $25 million available for funding.[50]

Stand-alone wind and solar energy will not have any significant role in providing grid resiliency – simply due to their variability and likely unavailability when the grid is down (i.e. inability to operate in islanded mode). However, if they are integrated into a microgrid with energy storage, that would enable utilization of previously stored wind and solar energy when needed later.

A fuel cell industry publication touts fuel cells as suitable solutions for affordable and reliable self-generation. It lists the following benefits for fuel cells[51]:

- Fuel flexible - operation on conventional or renewable fuels
- High quality, reliable power
- Exceptionally low/zero emissions
- Modularity/scalability/flexible installation
- Can operate independent of the grid

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[47] Ibid, pp 33-34.

[48] http://www.governor.ny.gov/press/02142013-20million-for-combined-heat-and-power

[49] 2011 New Jersey Energy Master Plan, Page 5. http://nj.gov/emp/docs/pdf/2011_Final_Energy_Master_Plan.pdf

[50] "Solicitation for The Large Scale CHP-Fuel Cells Program (2.0)", The New Jersey Economic Development Authority and The New Jersey Board of Public on January 17, 2013, with $25 million available for funding. http://www.njeda.com/web/pdf/LargeScaleCHPFuelCellsSolicitation.pdf

[51] The Business Case for Fuel Cells 2013: Reliability, Resiliency & Savings http://www.fuelcells.org/pdfs/2013BusinessCaseforFuelCells.pdf

- Extremely quiet
- Lightweight
- Rugged
- Can be used with or instead of batteries and diesel generators
- Can partner with solar, wind, and other renewable technologies
- Increased productivity
- Cost savings via high electrical and overall efficiency

In addition to this list of benefits, the same publication touts the reliability and resiliency benefits of fuel cells by providing a number of examples of business with installed fuel cells that could ride through storm-related power outages. Businesses mentioned included: Sheraton New York Hotel and Tower; Central Park Police Station; Whole Foods; Verizon Garden City Site; Octagon; an apartment building in New York City; and the Society of Cable Telecommunications Engineers (SCTE) headquarters in Exton, Pennsylvania.[52]

9.7.2 Distributed Energy Resources

Distributed energy resources (DER) are power generation and energy storage facilities interconnected to the utility system via a general-purpose feeder. DER can also be part of a microgrid, which supplies customers other than the customer or enterprise having the distributed resource, and can operate in isolation from the larger grid during times of emergency and storm events.

Distributed generation (DG) is a subset of DER, in which energy is converted from a primary source (fuel, wind, etc.) into electrical power. Distributed battery energy storage is also considered DER when connected to the customer's point of interconnection. Some definitions of DER also include demand response and other large controllable loads, such as plug-in electric vehicles.

DER can be small in size but large in numbers. In a future with increasing penetration of DER, individual systems may be aggregated across the utility service territory, especially within load centers, and work in combination to improve the quality and reliability of the power system. Coordinated operation of DER can be expected to provide and manage power supply in isolated regions, and ensure resiliency during event-related power disruptions.

9.7.3 Microgrid Applications

Innovations in DER technologies and developments in information and computer technology enable monitoring, visualization, communications, and command and control of distributed supply and demand in microgrid settings. These technologies may ensure continued operation of critical public services during emergency conditions, including entities such as first responders, hospitals, police and fire stations, water utilities, and wastewater treatment facilities.

Microgrids are essentially small-scale versions of the electric grid that include localized generation serving a specific cluster of loads and may also include renewables, demand response and storage.

[52] ibid, pp 10-11.

They offer the capabilities to run parallel with the Macrogrid or island and maintain energy delivery from local generation when the grid is not available.

Backup generators only support loads immediately attached to them and they usually come into action only during utility power outages. On the other hand, a microgrid may operate continuously with varying levels of on-site and grid resources.

Microgrids may include different combinations of diesel generators, gas turbines, fuel cells, photovoltaic and other small-scale renewable generators, storage devices, and controllable end-use loads that enable a group of facilities to operate in a utility-connected mode as well as in island mode, thereby ensuring high levels of reliability and resiliency.

During emergency operations, critical loads can be served first and other loads adjusted to not exceed the available generation capacity.

Potential tenants of microgrids include:

- **Medical Facilities:** Hospitals that need to seamlessly deliver patient care, regardless of weather or other extreme conditions.
- **Emergency Refuge Centers:** Sites and facilities which serve as first responder control centers and public refuge.
- **Educational Campuses:** These are also sites and facilities which can serve as first responder control centers and also as public shelters.
- **Corporate Campuses:** Large data centers supporting critical business operations. Colleges and Universities.
- **Urban Areas:** Densely populated urban areas where concentration of energy use is high and significant scale justifies connecting multiple buildings as part of a microgrid network (see the paragraph later in this section on the Central Hudson Gas & Electric Microgrid-As-Service)
- **Government and Military:** Local government facilities and military bases where power shutdown would pose unacceptable security risks
- **Critical Community Assets:** Critical community assets across multiple properties that would be included in "Public Purpose Microgrids", such as such as community centers, commercial hubs, emergency service complexes, and facilities that contribute to quality of life during an extended power outage (see the paragraph immediately below on Maryland Resiliency through Microgrids Task Force)

9.7.4 Maryland Resiliency through Microgrids Task Force

On February 25, 2014, Governor Martin O'Malley of Maryland directed his Energy Advisor to lead a "Resiliency Through Microgrids" Task Force to develop a "roadmap for action" to pave the way for private sector deployment of microgrids across the State. The Task Force made the following recommendations (abbreviated version):[53]

[53] http://energy.maryland.gov/MicrogridsandGridResiliencyinMaryland.htm

- For the short term, the Task Force recommends the State focus on the deployment of utility-owned public purpose microgrids through advocacy and incentives. Current law likely provides the Maryland Public Service Commission with authority to allow or require Maryland utilities to own and operate public purpose microgrids. A critical first step in this process is completing a pilot project in the State that would serve as a model for future deployment.
- For the long term, the Task Force recommends the State focus on reducing barriers to entry for third parties (non-utilities) wishing to offer public purpose microgrid services to multiple customers in Maryland, whether those services are offered in new developments or over existing electric distribution company assets.

As defined by this Task Force, "public purpose microgrids serve critical community assets across multiple properties. Critical community assets include resources that provide important community functions, such as community centers, commercial hubs, and emergency service complexes.

Facilities that contribute to quality of life during an extended power outage could also be included in a public purpose microgrid. A public purpose microgrid may be owned in whole or in part by either an electric distribution company or a third party entity, and must provide services to multiple customers across multiple property lines."[54]

9.7.5 Central Hudson Gas & Electric Microgrid-As-Service Filing

An interesting take on the role of utilities in developing microgrids is provided by Central Hudson Gas & Electric, which filed a rate case which includes a provision for development of regional subscription-based microgrids for business parks, campuses, urban areas or even neighborhoods.[55]

Central Hudson is proposing to offer microgrids-as-a-service for electricity customers, either a single large customer or an aggregation of many smaller customers with a total demand of 500 kilowatts or greater. The microgrid customers would enter into a service contract with the utility, which would build, own, maintain, and operate a custom-designed microgrid for those customers.[56]

GE Work on Microgrids

GE is currently engaged in a NYSERDA-funded study to investigate the technical and economic feasibility of a microgrid approach for five different locations in New York State containing public facilities that require power to sustain public health and safety during storm events. This is in addition to several other ongoing microgrid-related activities with utilities, state and federal entities. Based on these experiences, one of the key GE recommendations is that BPU continue to look at the value of microgrids and back-up generation to the state consistent with the energy master plan, and initiate techno-economic feasibility studies where practical (see SG-DA Recommendation SG-5 in Section 6.4).

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[54] "Maryland Resiliency Through Microgrids Task Force Report", Maryland Energy Administration, 2004, Page i. http://energy.maryland.gov/documents/MarylandResiliencyThroughMicrogridsTaskForceReport_000.pdf

[55] http://www.centralhudson.com/about_us/news/july25_14.html

[56] "Should electricity distribution utilities build, own, and operate microgrids for their customers?" MIT Energy Initiative, Jesse Jenkins, September 18, 2014. http://mitei.mit.edu/news/should-electricity-distribution-utilities-build-own-and-operate-microgrids-their-customers

Key findings:

- Traditional customer-owned back-up generation, often combined with storage, is used to provide extra redundancy to facilities with high reliability requirements, such as hospitals and data centers. Facilities with large thermal requirements can also sometimes justify DG as part of a CHP solution.
- Utilities currently face regulatory and business model barriers that inhibit ownership and operation of DG on customer facilities.
- Today's technology allows increasingly complicated and coordinated control of multiple DER (including customer demand response, storage, etc.) within a facility or among multiple adjacent facilities in close proximity.
- When multiple facilities or DER are connected behind a common point of control, and can operate in parallel or isolation from the larger grid, this arrangement is called a microgrid.
- DER and microgrids allow for higher levels of reliability and resiliency at a significant additional cost.
- A number of state and federal policy makers are currently exploring the value of microgrids as a regional storm resiliency strategy, by targeting clusters of critical public facilities, such as hospitals, police, fire, prisons, wastewater treatment, and emergency evacuation shelters.
- The benefits of microgrid are very site dependent and require detailed technical/economic feasibility studies to determine their value.

9.8 Advanced Metering Infrastructure

FERC's definition of AMI is:

> *"Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."*[57]

Advanced Metering Infrastructure (AMI), which includes both Smart Meters and associated communications and data management, is a key customer side component of many Smart Grid deployments. AMI, when equipped with "last gasp" notification capability, can contribute to power system resiliency and restoration of electric service following outages caused by storm damage.

DMS integration with Smart Meters via AMI provides control room operators with real-time information on outages rather than waiting for customers to call in. The ability to connect with these meters from the control room enables utilities to verify service restoration and power quality,

[57] http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

and notify customers via automated phone, email, or social media channels when service is restored.

Many utilities have installed AMI or Smart Meters, but have not integrated those meters with more sophisticated outage restoration processes to maximize their value during large scale storm events. As detailed in numerous anecdotal accounts, some of which are relayed below, in situations where AMI was deployed and effectively integrated with the utility's OMS, operators were better able to identify the location of outages and verify when power was restored.

The primary drivers for deployment of Smart Meters have been cost reduction and energy savings. But, the AMI network can also play a role in disaster recovery situations, leveraging the Smart Meters' capabilities as end-point sensors. The two main mechanisms are described below:

- **Real-Time Meter Updates:** Integrated distribution management systems, together with Smart Meters, provide control room operators with real-time information on outages rather than waiting for customers to call.

With AMI last gasp notification, utilities can immediately obtain detailed outage information across their territories, which if integrated with the utilities' Outage Management System (OMS), can help identify location of outages. AMI outage data contributes to the accuracy of the outage predictions, thus accelerating the identification of a fault location and enabling swifter restoration of service.

- **AMI Outage Intelligence:** AMI outage and restoration notification, as well as meter ping capability can greatly enhance restoration efficiency during storms. Smart Meter communications provide information on outage locations, allow power to be cut to certain areas to minimize the risk of fire or injury, and enable demand response to manage customer consumption of electricity in response to a stressed distribution system.[58]

  Verification of power restoration is accomplished when a meter reports in after being reenergized. This provides automated and positive verification that all customers have been restored and there are no nested or isolated outages before restoration crews leave the areas. Outage trails can also be used to identify the path of the storm damage.

A recent FERC Staff Report[59] documented a number of accounts of how advanced meters integrated with other technologies have helped keep the lights on and enable faster service restoration during severe weather events. Some of these are listed below:

- June 2012 "Derecho" wind storm, when advanced meters installed in Atlantic City Electric's service territory helped the utility predict the location and extent of outages, and deploy repair crews to areas where they were most effective.[60]
- June 2012, Electric Power Board Chattanooga (EPB Chattanooga) employed automated switches working in tandem with advanced meters to reduce the total number of customer

[58] "Demand Response Exceeds Expectations in Texas During January Grid Emergency", Advanced Energy Management Alliance (AEMA), Katherine Hamilton, May 2, 2014. http://aem-alliance.org/demand-response-exceeds-expectations-texas-january-grid-emergency/

[59] Assessment of Demand Response and Advanced Metering, Staff Report, Federal Energy Regulatory Commission, October 2013, Page 5. http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf

[60] Ibid, Page 5.

power outages by at least half, and avoided 58 million minutes of power disruptions for their customers. EPB Chattanooga was also able to restore power one and a half days sooner than would have been possible prior to the switch and meter upgrades, and the municipality realized $1.4 million in operational savings.[61]

- Similarly, during a separate storm event in April 2013, Commonwealth Edison reported that the use of automated switches and advanced meters prevented 20,000 service interruptions.[62]
- October 2012 Hurricane Sandy, Baltimore Gas and Electric (BG&E) and PEPCO noted that advanced meters assisted with efficient storm restoration, as well as customer outreach efforts, in Maryland and the District of Columbia. BGE was able to dispatch crews more efficiently by quickly identifying areas where power was already restored. Both BG&E and PEPCO noted that potential communication barriers were avoided by using advanced meter signals, instead of calling residential customers to confirm restoration of electric service.[63]

As reported in Greentech Media, "During Hurricane Sandy, 850,000 lost power in PEPCO's territory, accounting for more than half of PEPCO's 1.6 million customers. However, in the days after Sandy, PEPCO calculated that there were 50,000 customers who had a far shorter outage due to the utility's smart grid deployment, which include upgrades to the OMS to better communicate with AMR meters and the AMI technology."[64]

According to AMI vendor Itron, recent events have shown that tapping the data from AMI for more advanced outage detection capabilities has great value, as does knowing which circuits have been restored. Itron makes the following key points regarding the value of AMI-informed OMS:[65]

- Smart Meters can send power-outage signals over the network to the utility even when the power is out and they send restoration verification notifications when power is restored. For instance, CenterPoint Energy, San Diego Gas & Electric (SDG&E), and Detroit Edison (DTE) have integrated their advanced metering system into their Outage Management Systems.
- CenterPoint Energy is able to detect and understand the scope of an outage in about two minutes.
- AMI-informed outage management enables faster localization and lets the utility dispatch the right kind of resources to the exact location where it is needed and the dispatch time has been reduced from an average of 14 minutes to about 6, depending on the type of outage.
- AMI-informed OMS are more adept at finding "nested outages" when an individual customer or small number of customers are out under a single, secondary line or transformer, downstream of a known primary outage.

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[61] Ibid, Page 5.
[62] Ibid, Page 5.
[63] Ibid, Page 6.
[64] "A Smart Meter in the Superstorm - With increasing storms should come increasing data on how smart meters can help with power restorations", Greentech Media, Katherine Tweed, November 15, 2012. http://www.greentechmedia.com/articles/read/a-smart-meter-in-the-superstorm
[65] "Itron touts value of AMI-based outage management Firm's large IOU customers share 'dramatic' results", July 31, 2014, Page 1 +2. https://www.itron.com/publishedcontent/2014-07-31-SGT-OutageManagement.pdf

- SDG&E integrated the AMI data stream into its outage management system and can now detect an outage seven minutes before the first call comes in from a customer. The utility is typically able to respond to an outage event about 25 minutes sooner than before.
- Information on status and verification of restorations after outages are of high value. According to Itron, "In the case of DTE, they have integrated the system with their workforce management or field services system, so that outage crews can actually ping and query the meters out in the field, from their vehicles, when they are doing work, to ensure that power has been restored."

Looking at the future, other utilities are considering integration of AMI with advanced Outage Management Systems (OMS).

According to GreentechGrid publication report in 2012, "… during Sandy, a few utilities realized the advantages of their Smart Meters, including Baltimore Gas & Electric and PECO. Others are focusing on a 21st century OMS; Commonwealth Edison in Chicago is upgrading its system, for example, and EPB Chattanooga is already taking advantage of a cutting-edge system. SDG&E's northern neighbor, Pacific Gas & Electric, is also investing heavily in reducing outages."[66]

Successful integration of the AMI and OMS can be challenging, but possible with careful planning and the requisite testing and verification of the system performance. Some of the challenges and tips for overcoming them are highlighted in the BC Hydro experience, which is part way through integrating AMI and OMS[67]. Pitfalls identified by BC Hydro include:

- Automating small problems may turn them into big ones: Automation amplifies improvements, but it also amplifies problems, unless the AMI data usage is managed properly so that the repair crew is not automatically dispatched to deal with small problems.
- Expecting the technical integration to be straightforward: In most cases, the AMI vendors and OMS vendors are different, and hence, it may be a challenge to integrate a utility's AMI system with its OMS system and then test and verify the performance of the integrated system.
- Ignoring change management: Successful integration of AMI and OMS requires training and new processes to seamlessly utilize the AMI data and translate into crew mobilization and response.

Another utility that has highlighted the challenges faced in upgrading the OMS system with AMI is PECO, which notes that challenges were not necessarily technical, but more often related to processes. According to PECO Principal Engineer, Glenn Pritchard, "Training and change management is always key to this. I cannot stress this enough -- You have to spend as much time on the delivery of the product -- what the benefits are and how they'll use it."[68]

[66] "SDG&E Pushes the Envelope on Cutting Outages - All that sunshine doesn't stop San Diego from investing heavily in reducing outages", Greentech Media, Katherine Tweed, November 21, 2012. http://www.greentechmedia.com/articles/read/sdge-pushes-the-envelope-on-cutting-outages

[67] "Integrating AMI and OMS: Avoiding the landmines (from those who've gone before)", Smart Grid News, Apr 16, 2014.

[68] "Next-Generation Outage Management Paying Off in Pennsylvania: AMI and distribution system integration offer tangible benefits to PECO's decade-old OMS", Greentech Grid, Katherine Tweed, April 25, 2014. http://www.greentechmedia.com/articles/read/Next-Generation-Outage-Management-Paying-Off-in-Pennsylvania

PECO also considers its AMI + OMS solution a success: "The benefits have already started to pay off, particularly when Superstorm Sandy passed through in 2012. Despite the fact that the Smart Meter deployment was only about 10 percent complete at the time, PECO calculated that about 50,000 customers experienced much shorter outages than otherwise would have been the case, and more than 6,000 truck rolls were avoided in the aftermath of the storm."[69] For an integrated AMI plus OMS solution that would properly utilize the AMI data, one solution is to use an intermediary between AMI and OMS to fully validate and filter the power outage and restoration alarms from AMI before it is effectively used by an OMS.[70]

9.8.1 Status of AMI Deployment in New Jersey

The following table provides the latest information on the number of Smart Meters installed in the states on or near the Atlantic coast.

Table 9-1 Smart Meter Installations by Utility Type and State (July 2014)

State	IOU Smart Meters Installed	Municipal & Cooperative Smart Meters Installed	Total
CT	145,272	24,183	169,455
DE	315,000	11,982	326,982
FL	5,140,843	473,857	5,614,700
GA	2,460,139	722,011	3,182,150
MA	44,119	23,043	67,162
MD	1,878,000	0	1,878,000
ME	743,914	0	743,914
NC	223,209	279,488	502,697
NH	75,000	83,326	158,326
NJ	0	0	0
NY	4,100	20,581	24,681
PA	2,687,162	11,554	2,698,716
RI	0	201	201
SC	65,771	122,386	188,157
VA	236,053	153,332	389,385
VT	260,600	44,864	305,464

Data Source: "Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid", The Edison Foundation, Institute for Electric Innovation, IEI Report, September 2014.

The data shown in the above table may not be an exact representation, since the data was compiled by combining the IEI's 2014 smart meter survey, with responses from twenty utilities

[69] ibid

[70] T. Nielson and J. Wambaugh, "Tackling OMS and AMI Integration", UTILIMETRICS Quarterly, Fall 2012. http://uisol.com/new/wp-content/uploads/2013/01/tackling-oms-ami-integration.pdf

(representing 37 operation companies) and information from Energy Information Agency's Form 826 Advanced Metering worksheet and Smartgrid.gov's project information build metrics datasheet.

Table 9-2 below is provided from a FERC survey is provided for comparison:

Table 9-2 Estimated penetration of advanced metering by state in 2008 – 2012

	2008			2010			2012		
State	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration	AMI meters	Total meters	Penetration
DC	1,348	809,412	0.2%	2	275,554	0.0%	248,133	285,046	87.1%
CA	170,896	14,595,958	1.2%	2,475,896	14,837,434	16.7%	10,459,477	14,836,734	70.5%
ID	105,933	769,963	13.8%	198,370	803,576	24.7%	530,655	802,440	66.1%
GA	342,772	4,537,717	7.6%	514,403	4,401,623	11.7%	3,013,541	4,599,392	65.5%
AZ	96,727	2,810,224	3.4%	847,177	2,915,712	29.1%	1,646,410	2,977,092	55.3%
NV	10,835	1,292,331	0.8%	24,378	1,255,950	1.9%	717,220	1,299,632	55.2%
AL	139,972	2,774,764	5.0%	127,092	2,467,741	5.2%	1,397,672	2,604,431	53.7%
DE	0	438,020	0.0%	10,433	455,926	2.3%	310,890	593,583	52.4%
OR	39,797	1,890,423	2.1%	478,897	1,896,717	25.2%	960,151	1,874,339	51.2%
ME	426	780,748	0.1%	20,315	796,691	2.5%	671,036	1,372,735	48.9%
TX	868,204	10,870,895	8.0%	1,284,179	11,013,153	11.7%	5,948,975	16,987,336	35.0%
OK	161,795	1,875,325	8.6%	215,462	2,028,522	10.6%	703,091	2,071,552	33.9%
FL	765,406	9,591,363	8.0%	490,150	9,644,617	5.1%	3,052,570	9,771,192	31.2%
SD	41,191	475,477	8.7%	41,122	432,632	9.5%	109,586	440,774	24.9%
WY	12,268	318,282	3.9%	14,437	303,272	4.8%	70,650	308,024	22.9%
PA	1,443,285	6,036,064	23.9%	1,493,201	6,152,994	24.3%	1,623,982	7,753,238	20.9%
TN	60,385	3,160,551	1.9%	252,341	2,761,758	9.1%	724,469	3,738,153	19.4%
WI	117,577	3,039,830	3.9%	757,688	3,418,498	22.2%	562,861	3,107,700	18.1%
MI	73,948	5,311,570	1.4%	269,933	4,865,396	5.5%	738,702	4,859,675	15.2%
ND	33,336	375,473	8.9%	42,875	445,164	9.6%	61,329	407,033	15.1%
NC	143,093	4,771,479	3.0%	385,884	4,847,336	8.0%	644,811	4,832,250	13.3%
MS	3	1,454,275	0.0%	97,344	1,511,958	6.4%	201,877	1,584,994	12.7%
AR	168,466	1,488,124	11.3%	14,578	1,529,065	1.0%	162,181	1,559,849	10.4%
NH	260	763,683	0.0%	391	755,770	0.1%	76,864	743,454	10.3%
SC	114,619	2,373,047	4.8%	312,894	2,445,044	12.8%	246,526	2,417,863	10.2%
MO	204,498	3,098,055	6.6%	506,416	3,072,893	16.5%	299,375	3,061,397	9.8%
KY	105,460	2,161,142	4.9%	273,663	2,523,833	10.8%	313,094	3,353,259	9.3%
OH	28,042	5,544,353	0.5%	289,970	6,290,618	4.6%	638,167	7,267,087	8.8%
NE	8,630	970,774	0.9%	19,290	999,353	1.9%	83,342	977,513	8.5%
IN	61,551	3,115,205	2.0%	148,129	3,355,485	4.4%	275,821	3,342,734	8.3%
IA	46,407	1,714,774	2.7%	58,092	1,576,475	3.7%	124,975	1,623,036	7.7%
KS	61,423	1,426,832	4.3%	62,626	1,467,092	4.3%	110,628	1,452,858	7.6%
MN	37,071	2,542,113	1.5%	108,232	2,602,360	4.2%	203,717	2,709,254	7.5%
CO	39,873	2,246,184	1.8%	111,330	2,403,001	4.6%	183,658	2,446,657	7.5%
VA	6,448	3,965,584	0.2%	175478	3,663,525	4.8%	201,014	3,706,158	5.4%
CT	5,838	1,600,768	0.4%	1,967	1,625,758	0.1%	101,267	2,044,906	5.0%
MD	8	1,938,948	0.0%	4,189	2,483,628	0.2%	108,881	2,856,999	3.8%
MT	8,979	549,136	1.6%	27,470	577,745	4.8%	20,101	563,920	3.6%
IL	112,410	5,701,533	2.0%	286,568	6,099,158	4.7%	196,150	6,138,749	3.2%
MA	3,907	3,077,679	0.1%	20,831	3,150,098	0.7%	70,729	3,384,865	2.1%
WA	69,377	2,987,355	2.3%	128,857	3,298,781	3.9%	74,252	4,009,332	1.9%
UT	37	1,056,718	0.0%	20,046	1,083,069	1.9%	18,250	1,069,087	1.7%
LA	44,103	2,186,249	2.0%	53,848	2,245,066	2.4%	37,691	2,325,796	1.6%
NM	20,776	904,861	2.3%	54,250	1,015,058	5.3%	68,975	4,533,949	1.5%
AK	18	315,419	0.0%	3,835	316,289	1.2%	4,045	295,821	1.4%
NY	12,778	7,811,335	0.2%	28,664	9,313,776	0.3%	23,756	9,063,297	0.3%
NJ	9,866	3,900,716	0.3%	25,744	3,953,683	0.7%	13,768	6,062,487	0.2%
HI	6,550	405,228	1.6%	8,713	411,232	2.1%	737	484,479	0.2%
RI	148	480,135	0.0%	2,381	506,379	0.5%	210	477,183	0.0%
VT	20,755	375,202	5.5%	31,293	379,139	8.3%	128	398,300	0.0%
WV	10	1,183,513	0.0%	7,039	1,033,802	0.7%	280	1,051,585	0.0%

Source: "Assessment of Demand Response and Advanced Metering - Staff Report", Federal Energy Regulatory Commission, December 2012, Table 2-3

These two tables highlight the relative position of NJ with regard to number of smart meters installed compared to other eastern states. As can be seen, NJ has one of the lowest levels of AMI penetration in the US. However, the same is true for many of the Northeastern states. The penetration levels will most likely change with future surveys.

Many of these deployments are now several years old. As the technology has matured, today's AMI has more capabilities to provide more benefits, and should therefore have a better business case.

The NJ EDCs are in a position to benefit from these trends as "late adopters".

Key findings:

- The primary drivers for AMI adoption include utility cost savings from avoided manual meter reading and provision of better customer energy information (for dynamic pricing and demand response).
- Though not necessarily a primary driver of adoption, AMI systems also help reliability. Many smart meters come with "last gasp" capability that can aid in outage notification and verification of service restoration, both of which are beneficial in storm response and recovery.
- An emerging application is the integration of AMI data into OMS and DMS to provide greater situational awareness.
- Deployments of AMI are now widespread in many parts of the US, with tens of millions of meters in operation. Among Eastern states, Florida, Georgia, Pennsylvania, Maryland, and DC have significant deployments. New Jersey has so far not followed this trend.

9.9 Demand Response

Demand response (DR) consists of managing customer electricity demand based on either event or price signals (i.e., Dynamic Pricing). DR technologies and programs come in a variety of forms.

FERC's definition of Demand Response is:

> *"Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."*[71]

The principal DR Program objectives are Peak Load Reduction (reducing peak demand) and Load Shifting (shifting demand from on-peak periods to off-peak periods). Energy Efficiency and Energy Conservation programs, which some consider as part of DR, are meant to decrease the overall electricity usage (reduction of demand during all hours).

However, there is scant information, based on the actual experience, on the impact of demand response on grid resiliency and storm recovery. Demand response appears to have a limited role in storm recovery, but can help as a preventive measure in reducing the impact and severity of outages caused by severe weather events.

Two recent examples are:

[71] http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

- Demand Response played a role in helping Texas avoid rolling blackouts in the face of a polar vortex in January 2014. On Monday January 6, 2014, the Electric Reliability Council of Texas (ERCOT), the state's grid operator, warned of possible blackouts due to record-breaking cold snap and forced outage of two power plants. ERCOT called upon available demand response across the state, which helped keep the lights on.[72]
- Another example is the role of Demand Response in reducing demand during the heat wave of July 2011, when Demand Response was credited by Con Edison with reducing peak demand by approximately 500 MW.[73]

Although documented experience with DR during major weather events is lacking, it is reasonable to assume that DR can play a role in outage prevention and service restoration, mainly by preventing potential "brownouts". In particular, during storm events, when local outages impact supply, or damage to equipment creates congestion in the grid, DR can be employed to relieve local congestion constraints and mitigate supply shortages and hence prevent further disruption in power delivery. In the future, DR together with AMI technology may be integrated into a more robust and intelligent storm management system.

9.9.1 DR Program Types

Some types of DR rely on physical curtailment, where the utility directly interacts with device or facility level controls. Examples include programs Interruptible Load (IL), Direct Load Control (DLC), and industrial auto-DR. This type of program would be employed for emergency congestion relief. Unlike price-based programs, which have lengthier customer notification requirements, physical curtailment may be invoked quickly, in response to real time grid contingencies, which may not be predictable hours or days in advance.

The DOE's Energy Information Agency (EIA) defines IL and DLC as follows:

- Interruptible load (IL):

  "This Demand-Side Management category represents the consumer load that, in accordance with contractual arrangements, can be interrupted at the time of annual peak load by the action of the consumer at the direct request of the system operator. This type of control usually involves large-volume commercial and industrial consumers. Interruptible Load does not include Direct Load Control."[74]

- Direct Load Control (DLC):

  This Demand-Side Management category represents the consumer load that can be interrupted at the time of annual peak load by direct control of the utility system operator.

[72] "Demand Response Helps Texas Avoid Rolling Blackouts in the Face of Polar Vortex", Environmental Defense Fund Energy Exchange Blog, January 09, 2014. http://breakingenergy.com/2014/01/09/demand-response-helps-texas-avoid-rolling-blackouts-in-the-face-of-polar-vortex/

[73] "Early Response Planning", Con Edison 2011 Sustainability Report. http://www.conedison.com/ehs/2011annualreport/stakeholder-engagement/early-response-planning.html

[74] http://www.eia.gov/tools/glossary/

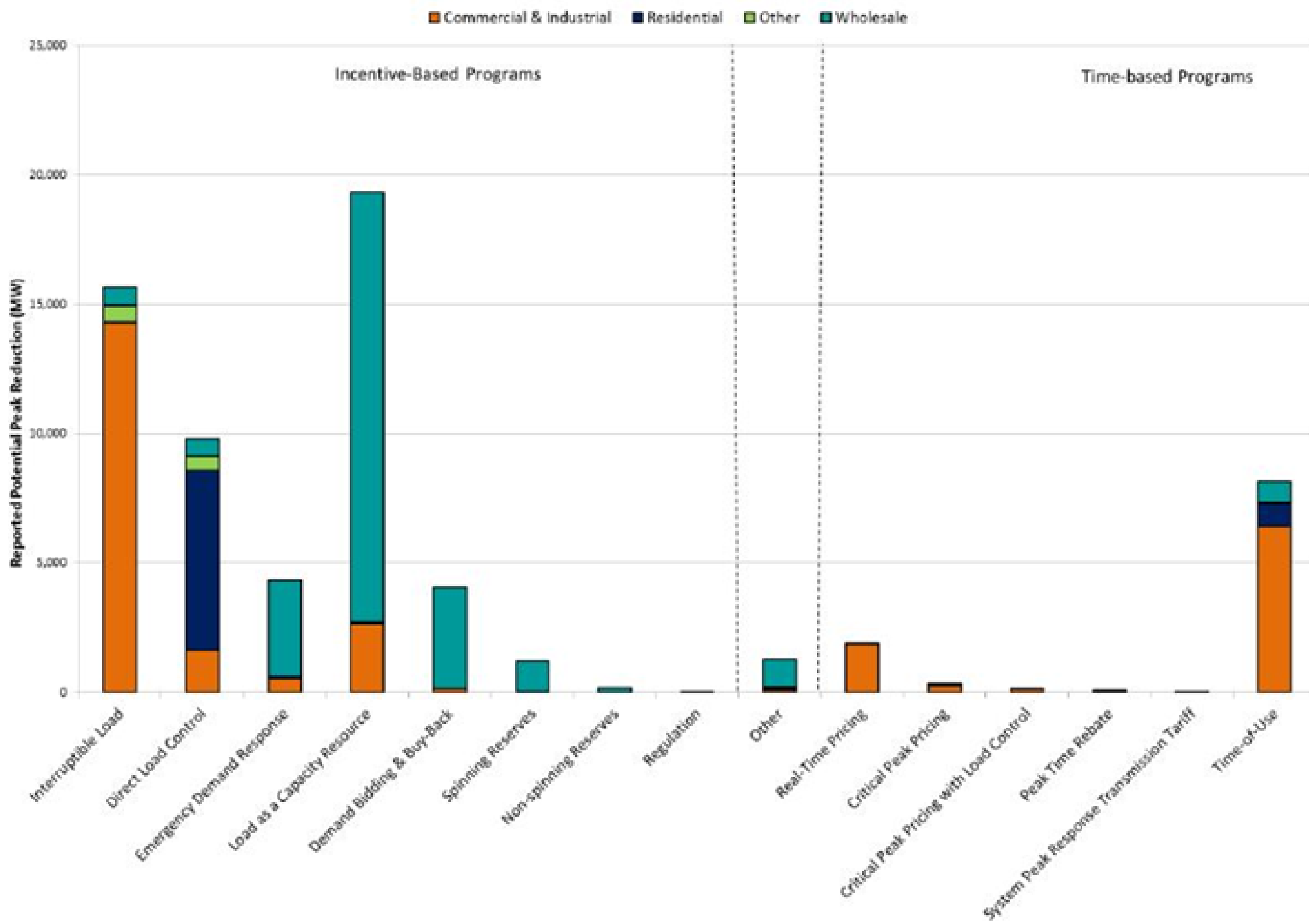
> Direct Load Control does not include Interruptible Load. This type of control usually involves residential consumers."[75]

Between these two, the greater response will most likely be from DLC customers, since they are under direct utility control and can be activated instantly by the active communication link at the first instance of expectation of blackouts. Traditionally, DLC communication has been via radio signals, which trigger the relays and switches installed at end-use devices such as HVAC, water heaters, pumps, and other electricity consuming devices. An important issue to note is that the older DLC systems in place are based on one way radio signal technology and their current operational status and responsiveness cannot be verified without manual on-site checking and testing. A two way system (e.g. integration with AMI) would be needed to ensure availability of these demand side resources during storm events.

The price responsive types of DR, which include various Dynamic Pricing Programs (i.e., Tim-Based Rate Programs), are less likely to be effective during unpredictable emergency conditions, when customers are likely to be distracted and far less attentive and responsive to price incentives. The U.S. Government's definition of Time-Based Rate Programs, include the following[76] (reproduced here verbatim):

- **Time-of-use pricing (TOU)** - typically applies to usage over broad blocks of hours (e.g., on-peak=6 hours for summer weekday afternoon; off-peak= all other hours in the summer months) where the price for each period is predetermined and constant.
- **Real-time pricing (RTP)** - pricing rates generally apply to usage on an hourly basis.
- **Variable Peak Pricing (VPP) -** a hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance (e.g., on-peak=6 hours for summer weekday afternoon; off-peak= all other hours in the summer months), but the price established for the on-peak period varies by utility and market conditions.
- **Critical peak pricing (CPP) -** when utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time period (e.g., 3 p.m.—6 p.m. on a hot summer weekday), the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one where the time and duration of the price increase are predetermined when events are called and another where the time and duration of the price increase may vary based on the electric grid's need to have loads reduced;
- **Critical peak rebates (CPR) -** when utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during pre-specified time periods (e.g., 3 p.m.—6 p.m. summer weekday afternoons), the price for electricity during these time periods remains the same but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility deemed the customer was expected to consume.

[75] Demand Response
[76] https://www.smartgrid.gov/recovery_act/deployment_status/time_based_rate_programs



Source: "Assessment of Demand Response and Advanced Metering - Staff Report", FERC, December 2012, Figure 3-5.

Figure 9-3 2012 FERC Survey reported potential Peak Reduction (by Program Type and Customer Class)

9.9.2 DR Deployment Status

As the above table indicates, IL and DLC have a significant role on load curtailment, with IL mostly on the Commercial & Industrial (C&I) customers, and DLC on the Residential customers. The following table illustrates the size of the DR programs for each state.

Table 9-3 Reported Potential Peak Reduction in Megawatts by Program Type and State

State	Time-Based	Direct Load Control	Other Incentive-Based	Emergency Demand Response	Interruptible Load	Other	State Total
AK	-	-	-	-	-	-	-
AL	183	17	-	-	1,647	-	1,847
AR	160	199	-	-	956	19	1,334
AZ	158	13	190	-	-	-	361
CA	381	612	1,112	256	660	-	3,020
CO	26	193	44	-	56	-	320
CT	-	-	48	339	5	-	392
DC	-	25	97	-	0	-	123
DE	117	76	186	-	20	9	408
FL	68	2,620	87	37	1,009	35	3,857
GA	686	244	7	-	328	-	1,264
HI	24	36	-	-	5	-	65
IA	3	136	346	154	605	-	1,244
ID	-	24	380	-	314	-	717
IL	9	189	1,658	58	1,298	-	3,213
IN	72	92	184	930	618	-	1,896
KS	25	65	28	20	249	-	387
KY	59	178	69	7	565	-	878
LA	-	67	-	-	-	-	67
MA	28	-	58	310	-	-	396
MD	232	822	1,357	-	66	-	2,478
ME	-	-	25	195	-	-	220
MI	3,383	240	1,306	271	550	86	5,835
MN	573	994	1,466	337	992	30	4,392
MO	84	40	-	-	83	-	207
MS	282	-	-	-	674	-	955
MT	3	-	-	-	-	-	3
NC	59	315	93	-	574	-	1,040
ND	116	295	18	6	-	-	435
NE	0	184	40	75	42	1,051	1,392
NH	-	-	11	62	-	-	73
NJ	-	112	786	9	3	-	910
NM	3	2	90	-	-	-	95
NV	-	130	-	32	-	-	162
NY	1	45	1,829	258	299	0	2,432
OH	3	88	2,536	44	475	-	3,145
OK	1,939	56	623	-	63	3	2,683
OR	-	1	14	-	6	-	21
PA	169	68	3,745	19	211	-	4,212
RI	12	-	11	74	-	-	96
SC	105	107	-	-	932	41	1,185
SD	13	605	-	18	20	-	656
TN	1,308	-	29	-	955	-	2,293
TX	4	71	1,943	420	137	2	2,577
UT	4	449	-	-	4	-	457
VA	85	118	1,988	10	82	-	2,283
VT	3	0	19	50	46	-	117
WA	1	1	1	-	20	-	23
WI	139	250	1,785	344	712	-	3,231
WV	-	-	560	4	364	-	929
WY	25	-	-	-	-	-	25

Source: "Assessment of Demand Response and Advanced Metering - Staff Report", Federal Energy Regulatory Commission, December 2012, Table 3-2.

As can be seen in FERC's 2012 survey, NJ had about 112 MW of potential DLC resources and 3 MW of potential IL resources. Taken together, there are not enough DLC and IL resources in NJ to have any significant impact on pre-emptive load reduction during major storm events. Developing more demand response type programs in NJ would provide additional flexibility in managing generation resources and reducing the potential for brownouts and blackouts during major storm events.

Key findings:

- Many types of DR programs have been developed to curtail discretionary loads and manage peak demand. Some of these involve pricing incentives (interruptible rates, TOU/VPP/CPP/RTP, etc.), while others communicate directly to specially equipped end-use devices (IL, DLC, AC cycling, AutoDR).
- DR can benefit storm response by providing flexibility to reduce localized grid congestion during periods of physical constraint (i.e. inadequate supply available to serve demand within a section of the grid). Physical curtailment is likely to be more effective in a storm context than price-based programs.
- At the current level of deployment in the U.S., the impact of any price signals based DR during storm emergencies is expected to be insignificant,

9.10 Grid Modernization Roadmap Integrating Multiple Smart Grid Technologies

An increasingly intelligent and digital grid is emerging - one enhanced with information technologies integrated with and extending the underlying analog circuitry and electro-mechanical infrastructure. New operational schemes involving automation, grid-level power electronics, distributed generation, microgrids, and energy storage are all becoming more established and will continue to evolve. Smart Grid represents a generational turnover in the core toolkit of the utility, bringing modern, digital information technology into all aspects of grid operations and planning.

A Smart Grid or grid modernization roadmap allows a utility to develop a secure and highly automated system that extends from smart meters all the way up to a distribution control center, with investments that may be staged or phased over the course of many years.

The Roadmap encompasses many aspects of SG technology that are relevant to storm response. A control platform that anticipates power concerns, monitors performance, and responds automatically to impending or actual outages and other power quality issues will greatly increase grid resiliency. Creating an integrated distribution management system will provide multiple analytical and decision support tools to help operators visualize and manage operation during recovery from extreme storm events.

The critical aspects of SG technology that are relevant to storm response include:

- **Hardened Communications Infrastructure:** The communications infrastructure is a critical element of grid operations and should be hardened with maximum resiliency.
- **Smart Meters:** Smart meters and related advanced metering infrastructure (AMI) installed and data collection integrated with other distribution management systems and analytics.
- **Intelligent Substations:** Substations upgraded with robust monitoring and automation and intelligent electronic devices (IEDs) spread across service territory.
- **Integrated Distribution Control Center:** Installing and integrating data and operational functions from metering/AMI, an outage management system (OMS) and a distribution management system (DMS).
- **Spatial Information:** Integrating a geographic information system (GIS) to provide a spatially robust network model which resides in the OMS.
- **Emergency Switching Plan:** A highly sectionalized distribution network, automated switching, and extensive controls
- **Social Media:** Use social media to better understand the location of a problem and to communicate with customers. This provides a significant amount of data that can be analyzed and visualized by the operators, maintenance, and field crews.
- **Storm Modeling and Decision Support Tools:** In-house developed system models and vendor-provided storm modeling and decision support tools to enable utilities to approach emergency response in a highly informed and systematic manner
- **Data Analytics:** Interpret multi-source data to ascertain real-time operating conditions and understand grid vulnerabilities as well as anticipate storm effects both before and during events.

Figure 9-4 SG modernization roadmap for increased storm resiliency and preparedness

Key findings:

- A Smart Grid roadmap allows the evolution and coordinated deployment of multiple technologies over a period of many years.
- The roadmap should address the many inter-related aspects of this technology transformation, such as the communications architecture, data management, cyber security, etc.; as well as behavioral factors: process change management, employee training, and customer communications.
- For storm resiliency applications, the roadmap will create a path towards deeper situational awareness for utility operators, integrating sources of data and control into a holistic view. This requires an evolutionary investment and development plan that starts with core infrastructure (communications platform), integrates individual hardware applications as they deploy (e.g. advanced sensors), migrates up through control room software and visualization (integrated DMS), and can eventually extend to include advanced data analytics, social media and mobile applications, and other future/emerging technologies not initially in scope.