Report

Electrical Transmission and Distribution Mitigation: Loss Avoidance Study

Nebraska and Kansas

FEMA-1674-DR-KS and FEMA-1675-DR-NE

April 2008

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ACSR	Aluminum-conductor steel-reinforced
BCA	Benefit-Cost Analysis
CRREL	Cold Regions Research and Engineering Laboratory
FEMA	Federal Emergency Management Agency
HMGP	Hazard Mitigation Grant Program
HMTAP	Hazard Mitigation Technical Assistance Program
kV	kilovolt
LA	Loss Avoidance
LAS	Loss Avoidance Study
MMC	Multihazard Mitigation Council
MP_A	Mitigation Project-Absent
MP_C	Mitigation Project-Complete
NESC	National Electric Safety Code
NPPD	Nebraska Public Power District
PA	Public Assistance Program
PDM	Pre-Disaster Mitigation Program
PI	Project Investment
PW	Project Worksheet
ROI	Return on Investment
RUS	Rural Utilities Service
SWPPD	Southwest Public Power District
T-2	Twisted pair
USACE	U.S. Army Corps of Engineers

This report, *Electrical Transmission and Distribution Mitigation: Loss Avoidance Study*, assesses the effectiveness of completed electric system mitigation projects in Nebraska and Kansas affected by the ice and wind storms of December 2006 through January 2007.

The Federal Emergency Management Agency (FEMA) awards mitigation grants to reduce the negative effects of natural hazards on property, people, and the environment. FEMA funds projects based on numerous factors, including a cost-effectiveness analysis of a range of probabilistic hazard events. Increasingly, policy makers want to know how projects perform during actual post-construction hazard events. The loss avoidance study (LAS) methodology was developed by FEMA to provide a quantitative approach to assess post-construction performance of mitigation measures.

This report represents the first LAS to be conducted for electric system mitigation measures intended to prevent damage from ice and wind storms. FEMA has funded a number of electric system mitigation projects throughout the Midwest. The extreme ice and wind storms of December 2006 through January 2007 provided an opportunity to examine completed mitigation projects and to develop and apply LAS methods. Past LAS reports have been organized around the three main phases of initial project selection, project effectiveness analysis, and loss estimation analysis. This same approach was used for this report, with new methods developed for the project effectiveness analysis based on modeling electric system damages from ice and wind events.

A total of three projects, located in Nebraska and Kansas, were chosen during the initial project selection phase. For these three projects, this report contains project descriptive information and the impacts to those projects from the 2006-2007 storm events. Damage analyses were also conducted for each project, resulting in an estimate in the damages that would have occurred had the project not been constructed.

The costs, in dollars, associated with system damages were estimated using loss estimation analyses. These analyses calculated the dollar amounts from physical damage and loss of function for pre- and post-mitigation conditions. The total losses avoided were estimated at $1.33 million .[1] The total project investment (based on the original project costs) for the three projects was $1.15 million. As a result, the overall return on investment for the December 2006–January 2007 ice and wind event was 115 percent.

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[1] All values given adjusted to 2007 dollars unless otherwise noted.

1. SECTION ONE   INTRODUCTION

Mitigation is defined as any sustained action to reduce or eliminate long-term risk to people and property from hazards and their effects. It is an activity that is practiced within numerous federal, State, and local entities and is identified as one of the primary missions of the Federal Emergency Management Agency (FEMA). Through nationwide programs such as the Hazard Mitigation Grant Program (HMGP), the Pre-Disaster Mitigation Program (PDM), and the Hazard Mitigation Technical Assistance Program (HMTAP), FEMA annually provides States and communities with substantial financial assistance for projects to mitigate or eliminate the risks associated with natural disasters. In 2007, FEMA had contributed financial assistance to several counties in Kansas and Nebraska who had ice storms resulting in federally-declared disasters.

With this type of investment, policy-makers take great interest in the effectiveness of mitigation. In response, a study was performed by the Multihazard Mitigation Council (MMC) under the direction of FEMA. The MMC Study: *NATURAL HAZARD MITIGATION SAVES: An Independent Study to Assess the Future Savings from Mitigation Activities* indicated that natural hazard mitigation saves an average of $4 for every $1 of investment (MMC, 2005). However, the MMC study used methods that assessed project effectiveness for probabilistic events. While this provides a theoretical measure of effectiveness, it does not demonstrate the effectiveness of mitigation projects for reducing or eliminating damage during actual hazard events.

To determine the effectiveness of mitigation during actual events, FEMA has developed a loss avoidance methodology based on the analysis of actual events. By conducting this analysis, FEMA (or any project sponsor) can quantitatively assess the benefits of the project in terms of its actual performance. These results demonstrate the effectiveness of the project and can be used to promote the value of investing in mitigation measures.

A Loss Avoidance Study (LAS) is used to verify potential effectiveness and document economic performance of mitigation projects. In doing so, studies look to answer the question "How much damage could have occurred from an event if the mitigation project had not been in place?" Further, an LAS provides comprehensive documentation of "losses avoided" (damages avoided or benefits) utilizing quantitative methods. These methods provide a reproducible and verifiable methodology that produces meaningful and defensible study results.

1.1   REPORT PURPOSE

The purpose of this LAS is to document successes from mitigation measures to electrical transmission and distribution systems. The scope of this study includes one mitigation project performed in Kansas and two mitigation projects performed in Nebraska that were funded through FEMA's HMGP program. This study answers the question "How much damage could have occurred from the Ice and Wind Storms of December 2006 through January 2007 event if the electrical systems mitigation projects had not been in place?" Further, the study provides comprehensive documentation of "losses avoided" (damages avoided or benefits) utilizing quantitative methods. This report describes a reproducible and verifiable methodology so that results of this study are meaningful and defensible.

This report presents an overview of the loss avoidance study methodology and describes its application to electrical systems mitigation projects. More specifically, it summarizes the

application of the LAS methodology to electrical systems mitigation projects in Kansas and Nebraska and provides the results of that study. Finally, it describes considerations and recommended best practices that were identified during the completion of the Kansas and Nebraska LAS.

This loss avoidance methodology described in this report was first provided in the *Loss Avoidance Study: Southern California Flood Control Mitigation. Part Two: Detailed Methodology* (FEMA, 2007a). The methodology from that report has been modified to provide for the wind-ice hazard analyzed in this report.

1.2   LOSS AVOIDANCE METHODOLOGY OVERVIEW

The approach used for this study quantifies losses avoided by completed mitigation projects using actual post-construction storm events for two separate scenarios: Mitigation Project-Absent (MP_A) and Mitigation Project-Complete (MP_C). All LASs consist of three phases, as shown in Figure 1.1. While Phase 1 and Phase 3 are the same regardless of the type of mitigation project or type of disaster being evaluated, Phase 2 varies depending upon the type of disaster and project. This study specifically focuses on the methodology used when assessing winter weather mitigation projects.
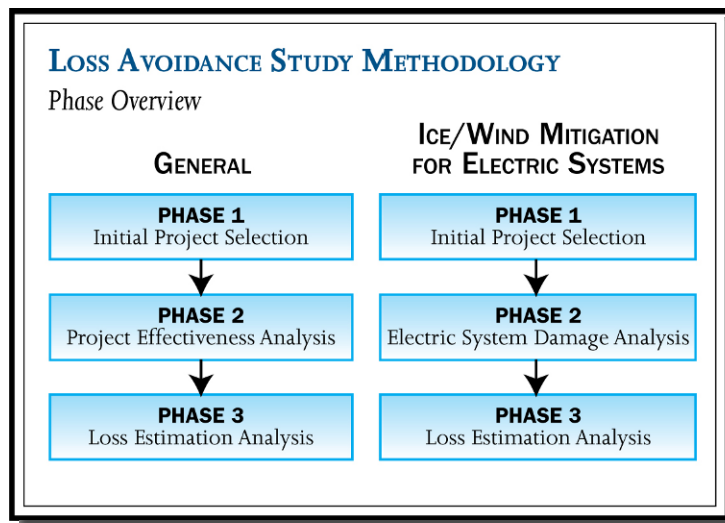
Figure 1.1: Overview of the Loss Avoidance Study Methodology

Phase 1 focuses on developing an initial project list. Projects are first selected based on parameters established for the study and then the selected projects are screened based on the availability of data necessary to complete the study. The resulting Phase 1 project list then proceeds to Phase 2.

The second phase of the methodology includes multiple analyses to determine if there are measurable avoided losses since the project's completion. For a storm event or events of interest, information on the actual damages incurred is gathered from local organizations

(electric companies or local governments) corresponding to the MP_C scenario. The actual damages are then compared to modeled damages and associated losses for the MP_A scenario, where the impacts of the event of interest are simulated under the pre-project conditions. This modeling consists of estimating system damages that may have occurred in the MP_A scenario and then determining the amount of time for power restoration.

The final phase of the methodology is the loss estimation analysis. There are two steps to this phase. An economic evaluation of the projects is completed for the two scenarios, MP_A and MP_C. The difference between the two scenarios is calculated and losses avoided (LA) are determined. The return on investment (ROI) is then assessed by computing the difference between project investment (PI) and LA.

1.3   EVENT OVERVIEW

A wide footprint of significant winter weather affected large sections of south central Nebraska and north central Kansas on Friday, December 29, 2006, through Sunday, December 31, 2006. Figure 1.2 shows the areas impacted by the 2006 storm, which included an area of the northeastern portion of Nebraska to the northwestern portion of the Texas panhandle. The storm brought freezing rain, sleet, wind, and snow. Most of the snow subsided Friday night while the sleet and freezing rain continued pressing further east to US Highway 183 in Kansas and US Highway 281 in Nebraska. By the end of the night on Saturday, the 30th, both States had experienced a significant amount of ice accumulation. Most affected locations received at least 0.5 inch of ice. Figure 1.3 shows an example of ice accumulation in Nebraska. The combination of ice accumulation on the power lines accompanied by high winds near the end of the storm resulted in significant damage to power transmission and distribution lines and poles. This resulted in widespread power outages. The storm's impact led to presidential disaster declarations in Nebraska (FEMA-1674-DR-NE) and Kansas (FEMA-1675-DR-KS). The impacted counties are shown in Figures 1.4 and 1.5.

Two reports provide information about this storm. The report titled *Evaluation of the Severity of the December 29-31, 2006, Ice Storm-Final Report for POWER Engineers, Inc*. (Jones, 2007), provides information about the observed and modeled ice levels. FEMA funded a second report, *Electrical System Impacts and Mitigation Strategies, Electric Cooperatives in Kansas and Nebraska, Ice and Wind Storms of December 2006 – January 2007* (FEMA, 2008), to provide more information on the damages to electric systems from the storm. The following sections summarizing the December 2006-January 2007 ice and wind storm event are based on these two reports.
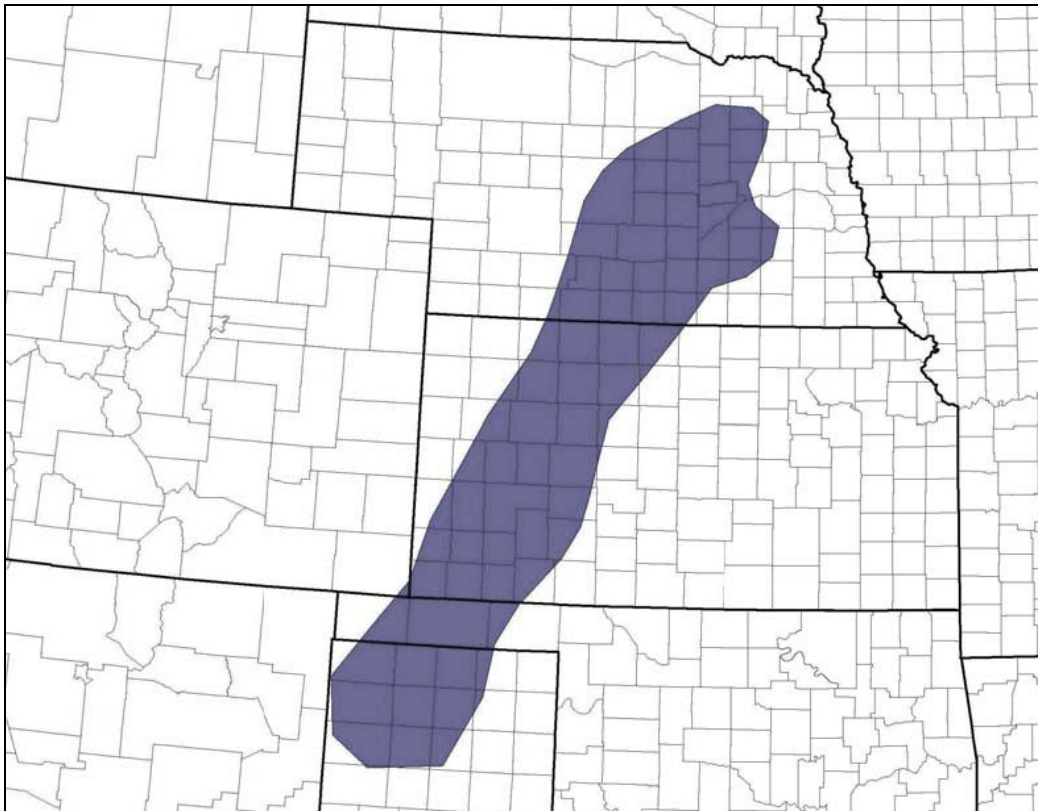
Figure 1.2: December 28-31, 2006 Ice Storm Footprint[2]

Figure 1.3: Illustration of Ice Accretion in Nebraska (Source: FEMA, 2008)

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[2] From "Evaluation of the Severity of the December 29-31, 2006, Ice Storm - Final Report for POWER Engineers, Inc." 2007. Kathleen F. Jones, U.S. Army Corps of Engineers, Cold Regions Research and Engineering Laboratory.
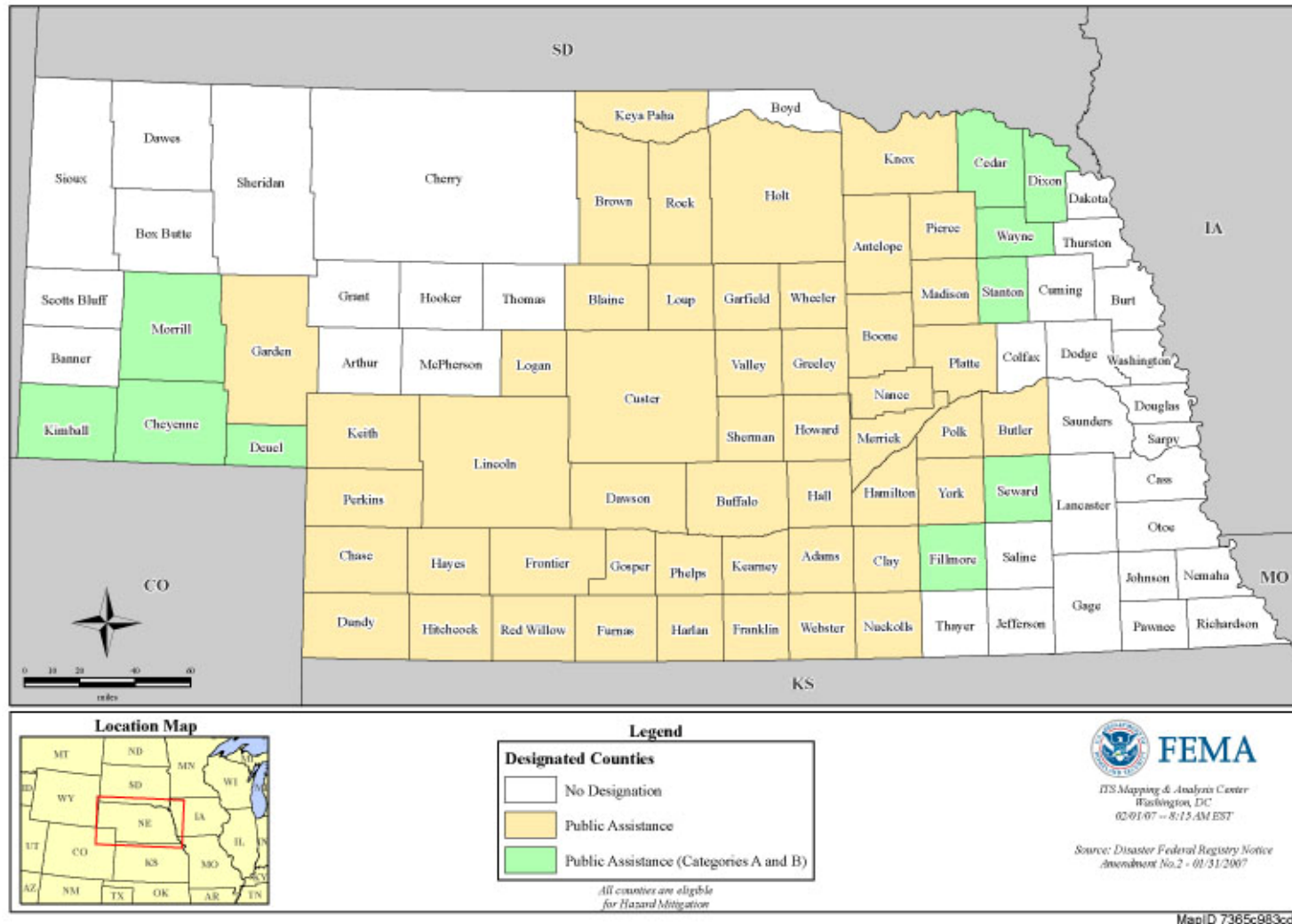
Figure 1.4: Nebraska Impacted Area (Source: http://www.gismaps.fema.gov/2007graphics/dr1674/dec_1674.pdf)
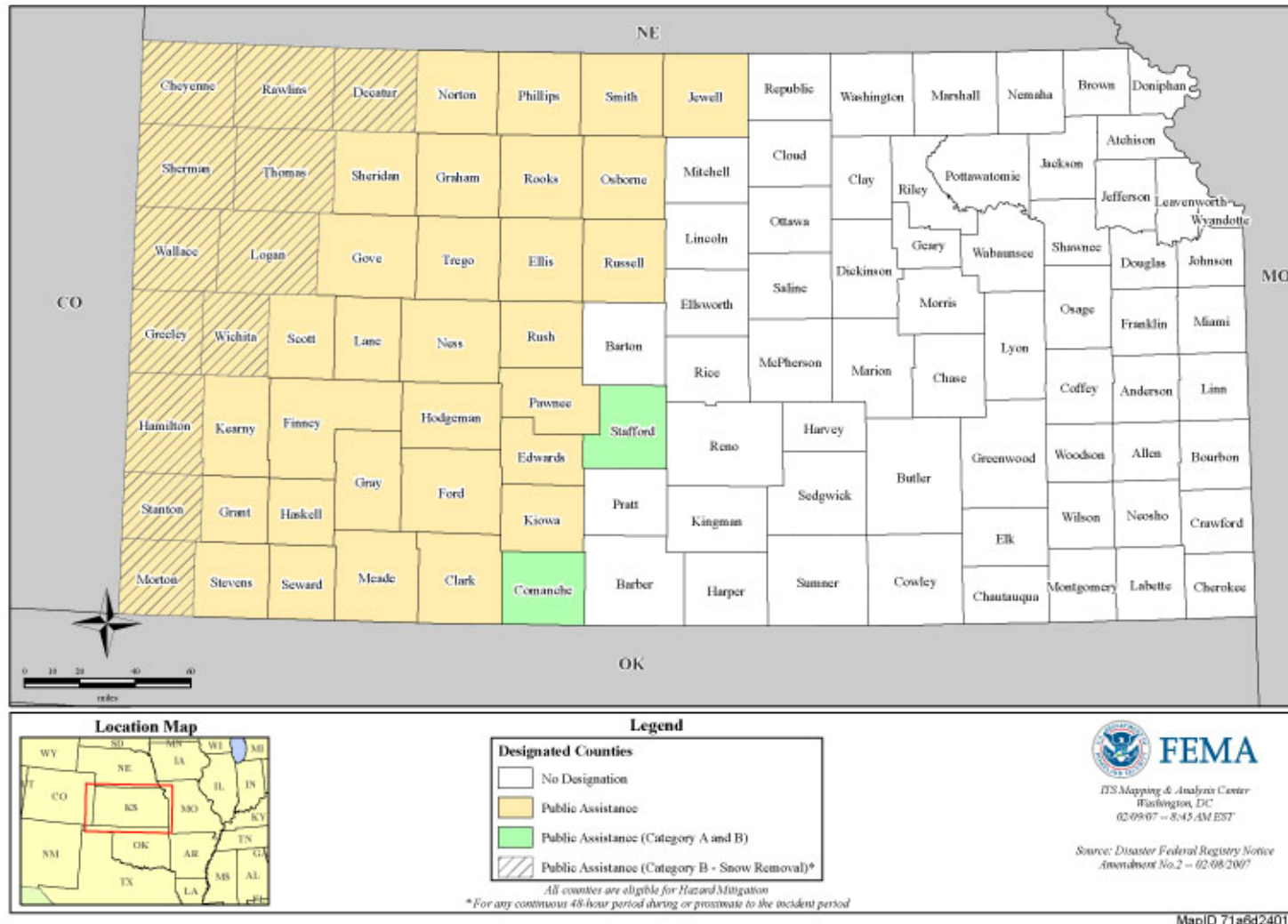
Figure 1.5: Kansas Impacted Area (Source: http://www.gismaps.fema.gov/2007graphics/dr1675/dec_1675.pdf)

1.3.1   Nebraska

The ice and storm event in late December 2006 and early January 2007 caused more than 35,000 Nebraska power customers to lose power and was reported as the worst ice and wind storm experienced in over 25 years (FEMA, 2008). The following counties had significant amounts of damage resulting from the storm: Platte, Thomas, Logan, Cunning, and Lincoln. There were nearly 13,000 power poles destroyed and approximately $200 million in damages to the infrastructure of the power grid. Damages included downed power lines, multiple destroyed H-frame structures, and steel lattice structure failures. The Nebraska Public Power District (NPPD), a large utility company within the State, reported that the failure of steel lattice structures caused a number of high-voltage (345 kilovolt [kV]) lines in the central part of the State to go down (FEMA, 2008). Figures 1.6 shows an example of steel lattice structure failures.

Figure 1.6: Failure of a Series of Steel Lattice Structures. (Source: FEMA, 2008)

1.3.2   Kansas

The December 2006 to January 2007 storm was the worse experienced by most of the northwestern part Kansas in over 10 years. There were more than 60,000 local power customers without power in the impacted areas of the State (FEMA, 2008). As much as 0.75 to 1 inch of radial ice accumulated on trees and power lines in southwest Kansas, west of a line that runs from Liberal to Dodge City to Wakeeney. Up to 2 to 3 inches of total ice accumulated in some parts of southwest Kansas causing significant damage (Jones, 2007). Approximately 10,500 utility poles toppled and 21 steel towers were damaged from the weight of the ice and strong north winds. These winds ranged from 25 to 40 mph. The greatest ice accumulations occurred along a corridor stretching from Hugoton to Ulysses to Dighton and Garden City in southwest

Kansas. In the western part of the storm area, moderate to heavy snow followed the ice, with 4 to 9 inches of accumulated snow and significant drifting (FEMA, 2008). Figure 1.6 shows storm-related failure of a wooden power line structure.

Figure 1.7: Failure of a Wooden Structure. (Source: FEMA, 2008)

2. SECTION TWO   PROJECT INFORMATION

This loss avoidance study focused on three mitigation projects, two located in Nebraska and one located in Kansas (refer to Figure 2.1). This section of the study report provides background information on each of the projects and the impacts from the 2006 storm. Information for this section comes from the FEMA project files and interviews with local officials.
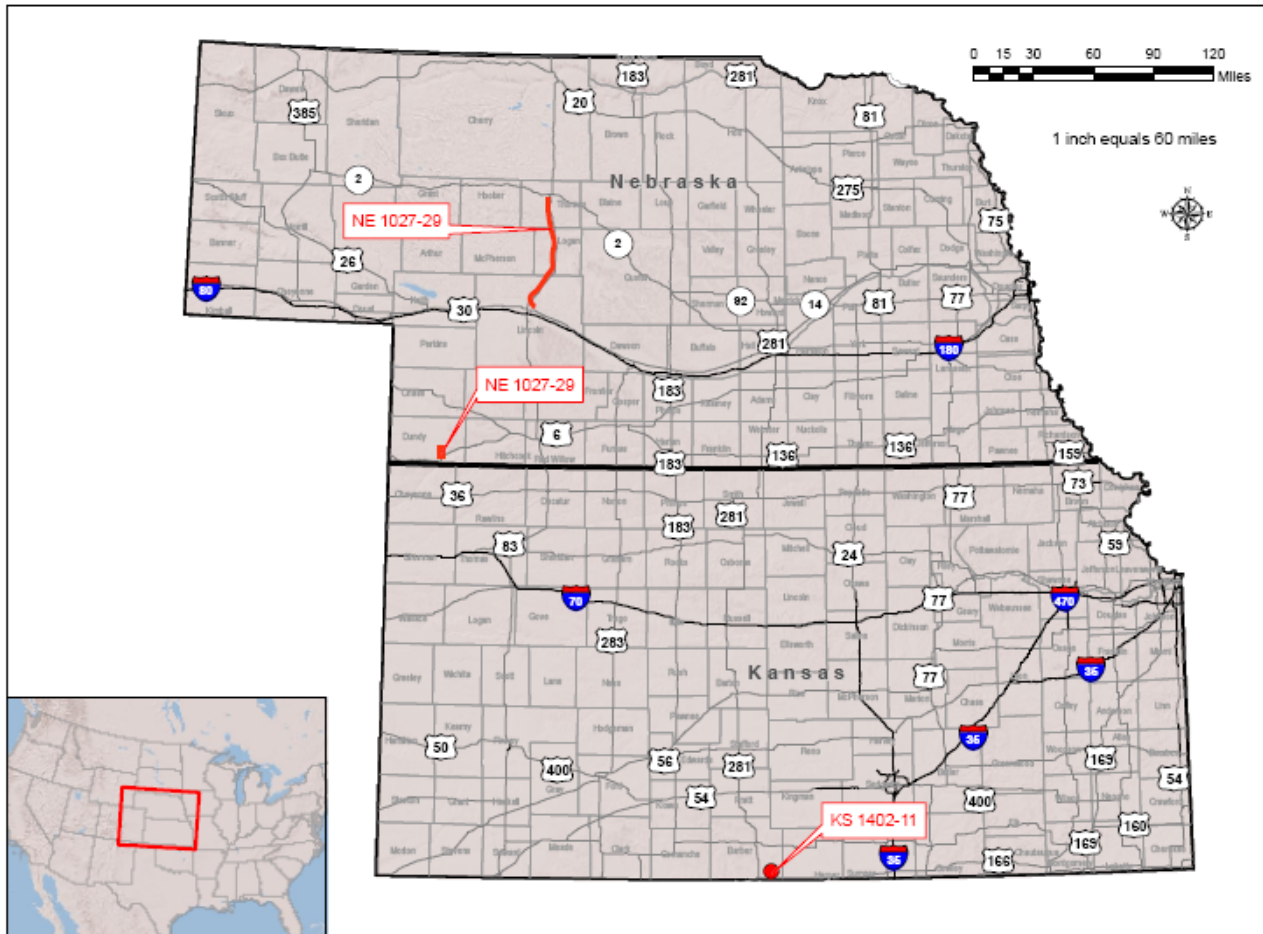
Figure 2.1: Map Showing Locations of Three Projects Included in This Study.

2.1   HMGP – NE –1027 – 0029 (SWPPD)

2.1.1   Project Description

Southwest Public Power District (SWPPD), with FEMA's help, devised a strategy to strengthen and replace single poles and install stronger conductors on an 11 mile stretch of 69-kV lines along U.S. Highway 61 in Nebraska. The 69-kV line along this stretch supplied power to approximately 14,000 customers. These poles and lines were susceptible to failure during high wind and ice storm events. The single poles were replaced in 2002 with new steel structures that met the Rural Utilities Service (RUS) standards. In addition, the conductors that were previously

susceptible to galloping were replaced with Twisted Pair (T-2) conductors that were not susceptible to this phenomenon. The overall cost associated with this mitigation project was approximately $482,723 in 2002 dollars, or $556,358 in 2007 dollars.

2.1.2   2006 Event Impacts

Gary Henken, project engineer for SWPPD, was consulted to determine the impacts of the December 2006 to January 2007 ice and wind storm on these power lines. Mr. Henken indicated that Dundy County, Nebraska experienced no damages to the mitigated portion of the 69-kV line, despite ice accumulation of approximately 0.5 inch at along that portion of the line. Mr. Henken reported that the major part of the storm hit farther east of Dundy County. Figure 2.2 shows the modeled estimate of radial ice equivalent (R_{eq}) from the storm for the region.
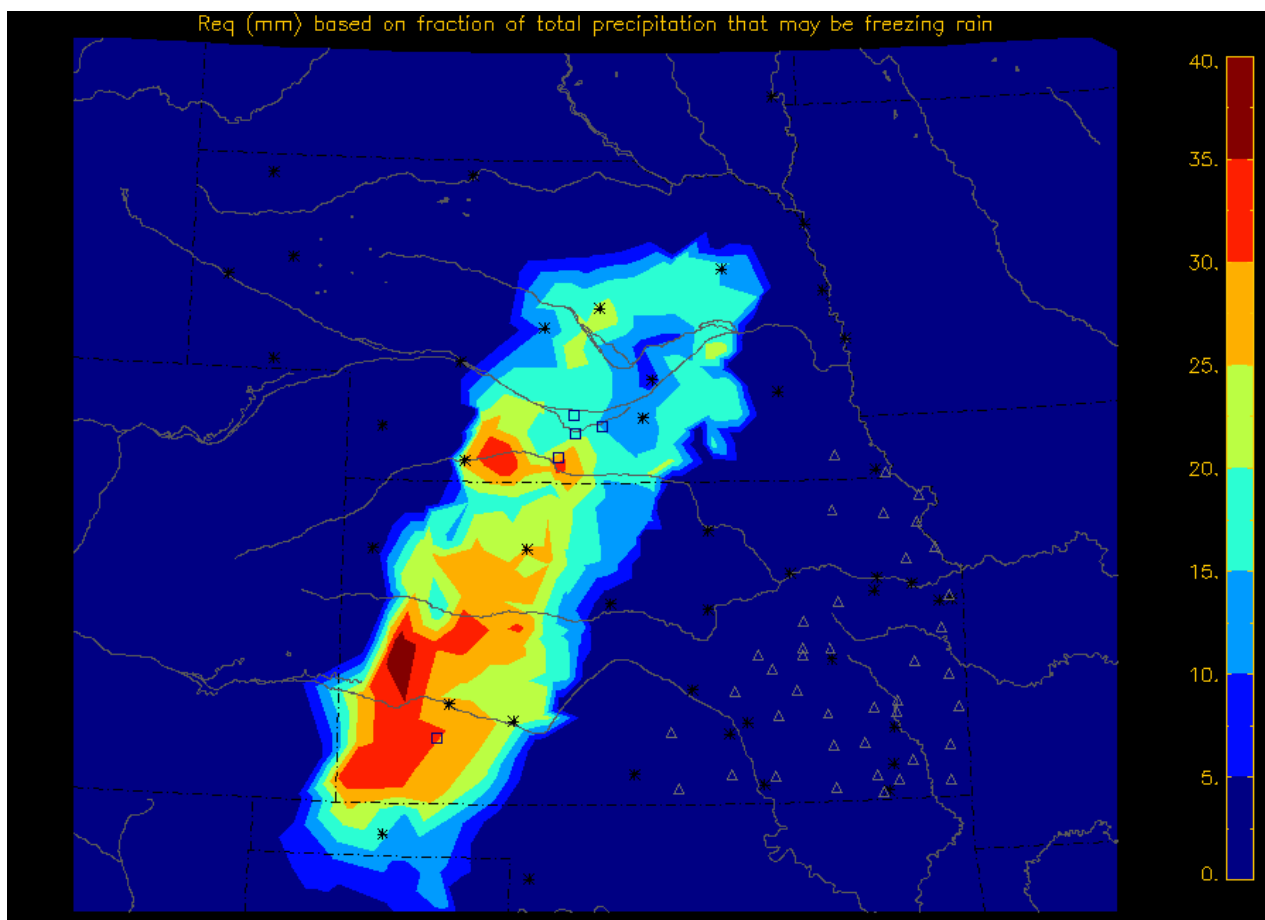
Figure 2.2: R_{eq} (millimeters) Estimated from Precipitation Data on Wires Perpendicular to Wind Direction (5 mm=0.2 inch). (Source: Jones, 2007)

2.2   HMGP – NE – 1517 – 0002 (NPPD)

2.2.1   Project Description

Nebraska Public Power District (NPPD), with FEMA's help, developed a plan in 2006 to replace existing transmission line towers with new "dead-end" structures to prevent the cascading effect

of power line failure during extreme wind, ice, and snow storms. The project involved installing 14 new "dead-end" towers at regular intervals on the following 5 independent transmission line segments in the central and northeastern parts of Nebraska:

- Phase 1: TL1161B – West Point to Beemer (Fall/Winter 2006)

- Phase 2: TL1166B – Stanton to Beemer (Fall/Winter 2006)

- Phase 3: TL1193A/B – Oakland to Emerson (Fall/Winter 2006)

- Phase 4: TL1078 – Maxwell to Thedford (Spring 2007)

- Phase 5: TL1097 – Belden to Twin Church (Fall/Winter 2006)

Only Phase 4 had been completed before the December 2006 to January 2007 storm occurred. Phase 4: TL1078 – Maxwell to Thedford included installation of six dead-end structures. This stretch of 115-kV transmission line along US Highway 83 supplied power to approximately 23,000 utility customers. The overall cost associated with this mitigation project was approximately $234,000 in 2006 dollars or $240,665 in 2007 dollars.

2.2.2 2006 Event Impacts

Sharon Brown, project coordinator for NPPD, was consulted to determine the impacts of the December 2006 to January 2007 ice and wind storm. Ms. Brown reported that there was 0.5 to 0.75 inch of ice accumulation in the Maxwell to Thedford corridor and that this phase of the mitigation project experienced no damages. Ms. Brown also stated that other phases of the mitigation project (the uncompleted phases), located in areas that had ice accumulations greater than 1 inch, experienced damages to the un-mitigated project segments and no damages to the mitigated project segments.

2.3   HMGP – KS – 1402 – 0011 (KIOWA)

2.3.1 Project Description

The City of Kiowa, Kansas, with FEMA's help, developed a plan in 2006 to upgrade 15 blocks of electrical power distribution systems. This plan included replacing distribution conductors, single poles, and transformers. The 15 blocks associated with the mitigation project supplied power to approximately 1,200 utility customers. The existing cooper and aluminum-conductor steel-reinforced (ACSR) open conductors were replaced with insulated spacer cable, and lightning arrestors were installed at each connection point on the conductors. The distribution poles were reconstructed and strengthened to prevent future failures from ice and wind loading and new three-phase transformers with polyethylene insulators were installed to prevent radio noise that could appear over time. The overall cost associated with the mitigation project was $345,768 in 2006 dollars or $355,616 in 2007 dollars.

2.3.2 2006 Event Impacts

The City of Kiowa was consulted to determine the impacts of the December 2006 to January 2007 ice and wind storm. The spokesperson at the City office indicated that Kiowa was on the outer range of the storm and experienced only a minimal amount of ice accumulation. Based on

Figure 2.2 from Jones (2007), this level of accumulation is assumed to have ranged from 0.2 to 0.5 inch. The spokesperson also indicated that there were no damages to any portion of the mitigation project.

3. SECTION THREE   LOSS AVOIDANCE ANALYSIS PHASE 1 – PROJECT SELECTION

The final project list was developed using the following steps:

1.   Develop an initial list of candidate mitigation projects

2.   Eliminate projects based on a decision analysis process that included a measurable ranking system and input from FEMA.

3.1   MITIGATION MEASURES FOR ICE AND WIND STORMS

One important consideration when evaluating past projects for inclusion on the initial project list is the overall intent of the mitigation measure. Certain measures provide mitigation for a range of storm severities, while some measures only provide protection above or below a certain storm severity threshold. Several mitigation measures for electric systems are detailed below. An effort was made to select projects representing a range of mitigation measures, specifically the ones described below. All of these mitigation measures were considered when developing the initial project list.

3.1.1 Dead-End Structures

One mitigation measure used for electrical distribution lines is a dead-end structure (FEMA, 2008). Dead-end structures are poles or transmission towers that stop the "cascading" effect. When a power line breaks, the unbalanced forces on the pole are significant enough to break the pole and cause a number of poles in each direction to break as well. A dead-end structure has guy wires attached to it that prevent the structure from bending. These wires also support the structure when a line breaks several poles down the line and prevents poles in line with the dead-end structure from breaking. Dead-end structures are intended to provide extra protection primarily for larger (more extreme) ice and wind events. During smaller storm events, the conditions needed to produce a cascade failure are much less likely to occur.

There are two types of dead-end structures, single-sided dead-end and double dead-end structures (Marne, 2006). A single-sided dead-end structure is the last pole on the line. The distribution line ends at this pole. The structure is reinforced by guy lines that are secured in the ground. If poles break near the single-sided dead-end structure, the guy lines will assist in keeping the dead-end structure upright. When an electrical conductor continues in a straight line for miles, a double dead-end structure may be inserted along the line to add strength, as well as to prevent cascading along the entire length of the line. A double dead-end structure is similar to a regular pole, in that it feeds the distribution line to the next pole; however, it also has guy lines that support the pole and prevent cascading from continuing past that point. Figure 3.1 shows a double dead-end structure where one side has experienced a cascade failure, but the end side remains intact.
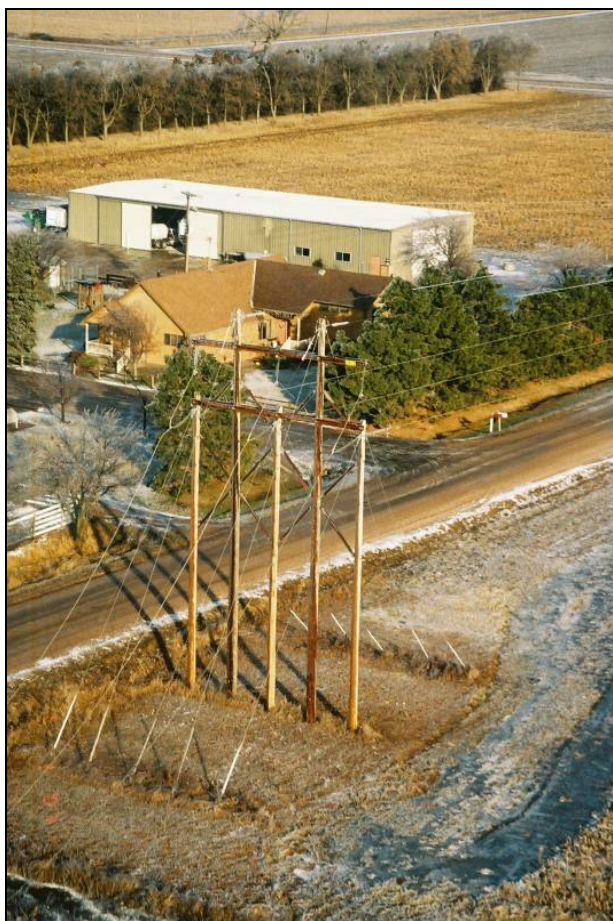
Figure 3.1: Double Dead-End Structure with Failure on One Side. (Source: FEMA, 2008)

3.1.2 System Strengthening

Another effective mitigation measure is to strengthen the lines and poles of distribution lines (Minnesota Department of Public Safety-Division of Emergency Management [MNDPS], 2008). For instance, existing lines can be replaced by heavier wire, such as T-2 and ACSR. T-2 wires consist of two wires that are the same size and made of the same materials; these wires are twisted together to form one stronger wire. Figure 3.2 shows a schematic of a T-2 wire. By creating a twist in the wires, airflow changes over the surface of the conductor. This action prevents uniform ice deposits from accumulating on the wire and reduces the risk of vibration and galloping. By preventing these occurrences, the line and poles are more likely to remain intact during ice and wind storms. Other methods of strengthening the line and poles include: creating shorter spans between poles, installing larger poles, and providing wind dampeners. Figure 3.3 shows T-2 distribution lines. Using these mitigation methods together increases the strength of the strength of the distribution line by 66 percent. These mitigation measures increase protection for events ranging in severity from small to large, up to the design limits of the systems.
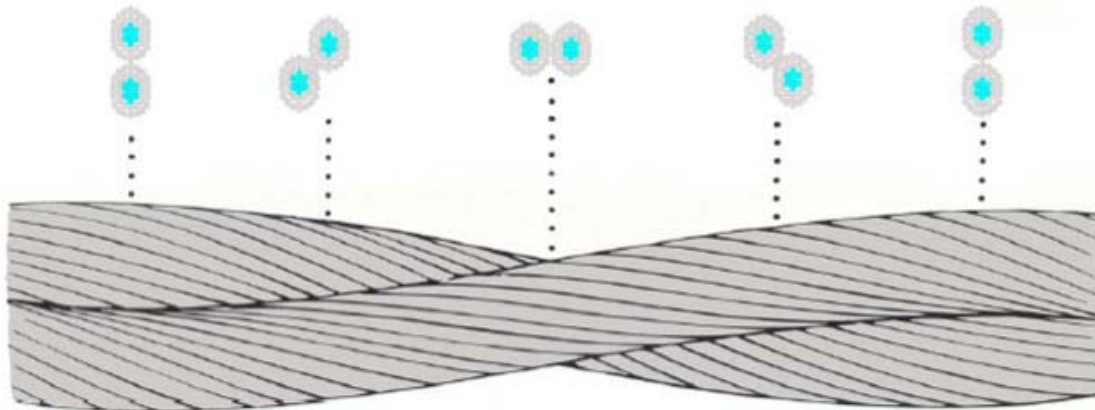
Figure 3.2: T-2 Conductor Schematic. (Source: EPRI, 2006)

Figure 3.3: T-2 Lines (Source: MNDPS, 2008)

3.1.3 Underground Conversion[3]

A third mitigation measure is to place the power lines underground. There are two methods for constructing underground lines. These methods are open trenching and trenchless construction. Open trenching involves digging a trench, inserting conduit into trenches, backfilling the trenches, and inserting power lines through the conduit. This method is typically used in areas with large right-of-ways. The second method, trenchless construction, involves boring a horizontal hole while simultaneously inserting conduit in the ground. Aesthetics and preservation of electrical service play a large part in implementing this measure. Research has shown that while placing power lines underground reduces the amount of interruptions to the power lines, it does not entirely eliminate interruptions. However, when compared to other mitigation measures, underground conversion would be expected to provide the most protection from both small and large storms.

The main issue with underground conversion is the cost. On average, it cost $957,858 per mile of line to convert overhead lines to underground lines in 2006. This value is 5 to 10 times that of new construction for overhead lines. A second major issue with underground conversion involves the time required to return service to customers after an outage. When power lines are overhead, the source of a power outage can be easily located and repaired. When power lines are underground, it takes longer to find the source of the problem and return service to those affected. The estimated repair time for underground conversion lines is 1.6 times that of overhead power lines.

3.1.4 Rerouting and Redundancy

The final major strategy to mitigate damage to electric systems from ice and wind events is rerouting lines and providing more system redundancy. This measure is highly dependent on the existing line configurations and history of failures. Sometimes, a specific critical facility, such as a hospital or fire station, has experience repeated outages. An effective mitigation measure may be to reroute an especially vulnerable section of line or provide a secondary feed in case the primary line is out. In many rural communities in the Midwest, there may be only one line and no redundancy. Rerouting power lines often involves other mitigation strategies, such as underground conversions. The effectiveness of rerouting and adding redundancy is very project-specific and tends to provide an incremental improvement over current conditions. For example, there may be on average a 3 hour power outage for a community 25 percent of the time for ice events of greater than 1 inch radial ice. Adding redundancy may reduce power outage time and/or the percent failure for certain events.

3.2 DEVELOPING THE INITIAL PROJECT LIST

Table 3.1 shows the initial project list for this study. Most of these projects are either dead end structures or system strengthening. The initial project list was based on the FEMA-funded projects that mitigated against damages from ice and wind storms. The area of interest spanned

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[3] Discussion is based on FEMA (2006a): *Identifying and Developing Effective Underground Conversion Projects*, EMW-2000-CO-0247 HMTAP TO 312.

several States. The development of the project list also considered the funding programs where electric system mitigation was eligible, such as FEMA's HMGP. The FEMA project files and databases were then examined to develop a list of candidate projects.

Because of the low number of FEMA-funded projects in Kansas, information about projects funded from some non-FEMA sources was also gathered by contacting Rural Electrical Cooperatives in regions of Kansas that had potentially been affected by the recent ice storm that resulted in Disaster Declaration 1675. Initially, eight Rural Electrical Cooperatives (RECs) in Kansas were contacted via electronic mail. When no responses were received within a week of issuance, attempts were made to reach these RECs by phone. One potential project candidate, CMS Electric Cooperative, Inc., resulted from these contacts. However, sufficient data was not available to develop project rankings and this project is not shown on Table 3.1.

3.3 DEVELOPING PROJECT LIST RANKS

All projects were prioritized based on the following weighted ranking system:

Score Criteria	Points
Successful unique, state of the art, or proven innovative measures implemented	Maximum 15 points
Benefit Cost Analysis Results	Maximum 30 points
Detailed Service Area Information (data about areas served by new items, population and businesses in service area)	Maximum 40 points
Information readily available (publically available databases, websites, existing publications and reports, detailed project files)	Maximum 15 points

Table 3.1 shows the project list with rankings for each project priority category and the overall score for each project identified for this study. The top three projects from this list were selected to proceed to Phase 2 of the LAS. All three projects sites were located outside of the "heart" of the impacted area with the greatest ice accumulation levels, but within the fringe of this area as indicated in Figure 2.1. The scope and schedule of this study required selecting projects based on information available a few months after the disaster, without the knowledge that the Jones (2007) report would be forthcoming. As stated in Section 6 (Recommendations) future loss avoidance studies for this type of winter storm would benefit from increased coordination with groups like the U.S. Army Corps of Engineers (USACE) Cold Regions Research and Engineering Laboratory (CRREL), who may provide information to better aid the project selection process

Table 3.1: Project List with Prioritization Ranks

General Project Information									Project Priority				
STATE Disaster Number	Incident Begin Date	Incident End Date	HMGP Project Number	Utility/REC	Type	Title	Project Counties	Benefit-Cost Ratio	Unique Innovative	Benefit Cost Analysis	Service Area	Available Information	TOTAL POINTS
NE 1027	4/10/1994	4/13/1994	29	Southwest Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Southwest Power Poles	Several	1.40	15	4	40	15	74
NE 1517	5/20/2004	6/1/2004	2	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD construction of 115 kV power lines to a higher standard	Burt, Cedar, Cuming, Dakota, Dixon, Lincoln, Logan, Thomas, Thurston	1.22	15	3	40	15	73
KS 1402	1/29/2002	2/15/2002	11	City of Kiowa	400.1: Utility Protective Measures (Electric, Gas, etc.)	Storm – Proof Power Lines	Barber	1.06	15	3	40	15	73
NE 1480	6/9/2003	7/14/2003	1	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Nebraska Public Power District	Antelope, Brown, Cherry, Holt, Thomas	11.04	5	30	30	5	70
NE 1027	4/10/1994	4/13/1994	8	McCook Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	McCook Public Power District	Frontier	8.80	5	24	30	10	69
NE 1286	8/6/1999	8/9/1999	3	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD – Mitigate exiting power lines and poles from continuing damages	Merrick, Nance, Platte	6.66	10	18	30	10	68
KS 1402	1/29/2002	2/15/2002	10	Heartland Rural Electric Co-Op	400.1: Utility Protective Measures (Electric, Gas, etc.)	Power Line Upgrade	Allen, Bourbon, Cherokee, Crawford, Lynn, Miami, Neosko	3.26	10	9	30	15	64
NE 998	6/23/1993	8/5/1993	23	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD – Power Lines and Poles	Statewide	4.33	10	12	30	10	62
NE 1627	11/27/2005	11/28/2005	2	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Installation of Storm Structures on Transmission Line 1133A, 1133C and 1080	Cherry, Furnas, Gosper, Red Willow	2.44	10	7	30	15	62
KS 1402	1/29/2002	2/15/2002	3	Butler Rural Electric Co-Op	400.1: Utility Protective Measures (Electric, Gas, etc.)	Power Line and Switch Upgrade	Butler	2.09	10	6	30	15	61
NE 998	6/23/1993	8/5/1993	21	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD – Power Lines and Poles	Statewide	3.55	10	10	30	10	60
NE 1373	4/10/2001	4/23/2001	1	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Nebraska Public Power District	Cheyenne, Deuel, Frontier, Keith, Lincoln	3.43	10	9	30	10	59

General Project Information									Project Priority				
STATE Disaster Number	Incident Begin Date	Incident End Date	HMGP Project Number	Utility/REC	Type	Title	Project Counties	Benefit-Cost Ratio	Unique Innovative	Benefit Cost Analysis	Service Area	Available Information	TOTAL POINTS
NE 998	6/23/1993	8/5/1993	22	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD – Power Lines and Poles	Statewide	2.78	10	8	30	10	58
NE 1190	10/24/1997	10/26/1997	3	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Rebuild High Voltage Lines	York	2.62	11	7	30	10	58
KS 1402	1/29/2002	2/15/2002	5	Twin Valley Electric Co-Op	400.1: Utility Protective Measures (Electric, Gas, etc.)	Conductor/Line Upgrade	Labette	1.13	10	3	30	15	58
NE 1394	8/17/2001	8/18/2001	1	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Nebraska Public Power District	Chase, Hayes, Hitchcock	2.46	10	7	30	10	57
NE 1027	4/10/1994	4/13/1994	11	Southwest Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	SWPPD – Strengthen Lines	Hitchcock	2.17	10	6	30	10	56
NE 1190	10/24/1997	10/26/1997	13	Southwest Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Southwest Public Power District	Several	1.40	11	4	30	10	55
NE 998	6/23/1993	8/5/1993	25	Southwest Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	Southwest Public Power District	Several	1.40	10	4	30	10	54
NE 1190	10/24/1997	10/26/1997	2	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD Rebuild High Voltage Lines	Several	1.06	11	3	30	10	54
NE 1027	4/10/1994	4/13/1994	12	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD – Power Line	Several	1.13	10	3	30	10	53
NE 1027	4/10/1994	4/13/1994	14	Nebraska Public Power District	400.1: Utility Protective Measures (Electric, Gas, etc.)	NPPD	Statewide	1.04	10	3	30	10	53
KS 1462	5/4/2003	5/30/2003	1	Caney Valley Electric Co-Op	400.1: Utility Protective Measures (Electric, Gas, etc.)	Switch and Transmission Line Rebuild	Chautauqua	1.13	10	3	30	10	53

4. SECTION FOUR LOSS AVOIDANCE ANALYSIS PHASE 2 – DAMAGE ANALYSIS

This section discusses Phase 2 of the loss avoidance methodology, the Damage Analysis. As with Phase 1, projects with inadequate data may be eliminated during the Phase 2 analysis. This Phase used a modified benefit-cost analysis method to determine system damages and the resulting loss of power. The report titled *Ice Storm of 2002: Four rural electric cooperatives in Kansas* (FEMA, 2003), describes the development and application of a new benefit-cost analysis method applied to four rural electric system ice and wind upgrades in Kansas. This method provides a step-by-step approach to quantify the predicted damages to components of electric systems from differing winter storm (ice) severities. Based primarily on the damage probability to poles, the method calculates damage and repair times for the following:

- Poles
- Wires
- Cross-Arms
- Guy Wires
- Pole-Mounted Transformers

This method can be modified for a loss avoidance analysis of electrical systems in the Midwest, as detailed in Appendix A. The following sections provide information on the type of damages caused by ice and wind to electrical systems (Section 4.1) and a description of the application of benefit-cost analysis method for loss avoidance (Section 4.2).

4.1 ELECTRICAL SYSTEM DAMAGE OVERVIEW

The following text for Section 4.1 is taken directly from the report titled *Ice Storm of 2002: Four rural electric cooperatives in Kansas* (FEMA, 2003) and is provided as background information.

Electric Systems

Electric power systems have three main elements: generation of power, transmission of power, and distribution of power.

- Generation means the actual production of electricity at power plants that may be fueled by fossil fuels (gas, oil, or coal), nuclear energy, hydroelectric facilities, or other sources (e.g., wind, biomass).

- Transmission means high voltage systems that convey power from generating plants to local distribution systems.

- Distribution means the low voltage local systems that connect individual customers to the electric grid. Transmission and distribution systems are each controlled by a series of substations which progressively step down voltage and control the flow of electric power.

Physical Damage from Ice Storms

Ice storms result in damage to electric systems when the lines and poles can no longer support the additional weight from ice and wind. Common failures include line breakages, pole cross-arm failures, and pole failures. Other electric system elements, including the lines (drops) to individual customers, transformers, switches, insulators, and substation equipment, may also fail in ice storms.

The vulnerability of lines and poles to wind/ice damage depends on the type, condition, and spacing of poles, on the types and number of conductors (wires), and on the locations of dead-end poles. Most poles in electric systems are designed for symmetric loads (i.e., to support balanced weights of lines on each side of the poles). When a line breaks on one side of a pole, the pole may not have the capacity to support the one-sided load, and thus a single line break may lead to a domino effect of cascading pole failures. Dead-end poles are stronger poles, usually stabilized with guy wires, which are capable of supporting a one-sided load. Everything else being equal, a greater number of dead-end poles in a system reduces the extent of system damages and outages in any given ice and wind storm event.

In addition to failures from direct ice and wind loading, lines and poles are also subject to failure from tree falls, which are very common in ice storms. Design loads for lines and poles do not include tree fall loading, and thus even new lines and poles are subject to failures from tree falls. Thus, the vulnerability of an electric system to ice and wind damage depends significantly on the robustness of the utility's tree-trimming and maintenance programs.

In general, distribution system lines and poles are more prone to failure in ice storms than are transmission line systems. Transmission lines are generally designed to similar ice and wind loading standards, but are typically located on taller poles, which make the lines less likely to be impacted by tree falls.

Over time, the design standards for poles and lines have changed significantly. Newer lines (post circa 1970) commonly use aluminum conductor, steel-reinforced (ACSR) lines that are stronger than older copperweld conductor (CWC) lines. Older poles are sometimes smaller in diameter with weaker cross-arms, and may also have age-related damage or degradation over time, thereby adversely affecting the ice and wind capacity of older portions of the system.

Lines and poles have a long service life and, therefore, many systems may have a substantial inventory (actually, a majority of inventory in most cases) that pre-dates modern design standards (circa 1970). Many systems have substantial inventory of old lines and poles dating back as far as the 1940s and 1950s.

Ice-Based System Design

The National Electric Safety Code (NESC), which is widely used for design of electric utility systems, provides for three grades or design levels of overhead line construction (lines and poles): Grade N, Grade C, and Grade B. Grade N is the minimum code level for lines designed to withstand normal expected loads, including personnel working on the structures. Grade C is the construction standard for distribution lines to modern code. Grade B is an "extra stout" construction standard for distribution lines to modern code, including an extra margin of safety capacity compared to Grade C.

Small rural electric systems often use transmission and distribution line design manuals published by the RUS, which is commonly referred to as the Rural Electrification Administration (REA). RUS/REA designs are generally very similar to the National Electric Safety Code (NESC) standards summarized above. For the current evaluation, NESC design standards are used as the reference because all four utilities described their design basis for new lines in NESC terms (Grade C or Grade B).

Factors Affecting Damage to Distribution Lines in Wind and Ice Loading

There are a number of factors that contribute to the likelihood and extent of distribution line damage under combined ice and wind loading:

- Strength of pole. The strength of a wood pole varies according to the type of wood used, length of pole above and below the ground, diameter of pole at the bottom and top, spacing between the pole, and external bracing (guy wires).

- Strength of conductor. The strength of the conductor varies based on its material of construction (copper, aluminum, steel), its diameter, its temperature, and its span between poles.

- Dead-end poles. The strength of a line is partly affected by the number and location of dead end poles. The sudden breakages of a wire between two poles will cause an unbalanced load on a pole, possibly leading to failure of that pole, which in turn unbalances the load on the adjacent pole, and so on. The spacing of dead-end structures (poles with guy wires) sufficient to withstand the unbalanced loading is optional; a more reliable line will have more dead-end structures. It will cost more to install and maintain on a regular basis, but possibly cost less under irregular loading conditions.

- Amount of ice and wind. The amount of ice on a wire will depend upon the amount of freezing rain that accretes on the wire. It is generally assumed that ice will continue to accumulate during an ice storm until the temperature rises sufficiently to melt the accumulated ice. During the storm, there will usually be varying amounts of wind with resultant loading on the ice-covered wire (whether with or without icicles). The "worst" loading case occurs during maximum wind at the end of ice accumulation, before ice starts to melt. The direction of the wind also has a major role; wind blowing transverse to a wire applies much more load than wind blowing parallel to a wire.

- Tree falls. Ice loading on trees will often cause damage to tree limbs, ranging from limbs or trunks sagging on a wire to limbs or trunks falling onto a wire. Falling tree limbs and trunks can cause a temporary or permanent short circuit (system remains intact, but may require manual or automatic action to reset the short circuit), excessive sagging in the line (causing unsafe clearances and requiring repair before re-energizing the line), or physically break the conductor or pole.

4.2   DAMAGE ANALYSIS OVERVIEW

Appendix A of this report provides details of the modification and application of the benefit-cost analysis methodology (as described in the report *Ice Storm of 2002: Four rural electric*

cooperatives in Kansas (FEMA, 2003) for loss avoidance analysis. The three major steps of the analysis are:

1. Collect project data (Section 4.2.1)

2. Determine system failures for MP_A scenario (Section 4.2.2)

3. Determine the time for system restoration for MP_A scenario (Section 4.2.3)

4.2.1 Collect Project Data

The minimum data requirements for conducting a loss avoidance analysis for an electric system mitigation project are listed in Table 4.1.

Table 4.1: Project Data Requirements

Data Requirement	Description
MP_A System Design	Information about the electric system for the MP_A scenario, including: • NESC System Grade (N, C, B) • Urban or Rural Setting • Tree Cover
Mitigation Project Design	Information about the mitigation project, including: • Project location and design (including miles of improvements or number of poles and NESC System Grade of improvements) • Population affected by project • Project Cost
Storm Event Information	Information about the ice and wind event of interest, including: • Radial ice equivalent for project location • Actual damages (in dollars) to project

MP_A system design information describes the condition of the project location prior to mitigation. The mitigation project design defines the mitigation measures and improvements that were installed. Finally, the storm event information pertains to a specific event of interest, the severity of the event, and any impacts on the improved system. Table 4.2 summarizes these data for the three projects analyzed in this study.

Table 4.2: Data Collection Summary

Project	MP$_A$ System Design			Mitigation Project Design			Storm Event Information	
	MP$_A$ System Grade	Setting	Tree Cover	Pole equivalent improved by project	Population affected by project	Project Cost (2007 dollars)	2006-2007 Event Radial Ice Equivalent (inches)	2006-2007 Event MP$_C$ Actual Damages
HMGP-1027-0029 (SWPPD)	NESC Grade N	Rural	None (Transmission lines)	198 poles (11 miles rural)	14,000	$556,358	0.50	$0
HMGP-1517-0002 (NPPD)	NESC Grade N	Rural	None (Transmission Lines)	702 poles (average of 39 miles protected by dead-end structures)	23,000	$240,665	0.75	$0
HMGP-1402-0011 (Kiowa)	NESC Grade N	Urban	Heavy	36 poles (1 mile urban)	1,000	$355,616	0.50	$0

The NPPD project pole equivalent requires further explanation. The benefit-cost analysis for the NPPD dead-end structures indicated that damages are reduced by 2/3. This means that when a pole fails during conditions that might cause cascade failures, only 1/3 of the total line is predicted to fail. Therefore, the use of the 6 dead-end structures is the equivalent of strengthening 2/3 of the total line. For damage calculations, this results in equivalent poles for 2/3 of the total length line length of 58.4 miles, which equals 39 miles or 702 poles.

4.2.2   Determine System Failures for MP$_A$ Scenario

The next step in the damage analysis is to determine probability of failure for the MP$_A$ scenario for the event of interest. The method described in *Ice Storm of 2002: Four Rural Electric Cooperatives in Kansas* (FEMA, 2003) starts with an estimate for pole failure and then applies this estimate to the other system components. Table 4.3, taken from Appendix A of that report, was used to provide the probability of pole failure as a function of equivalent ice radius, electric line construction type, and tree cover.

Table 4.3: Pole Failure Probability

Radial Ice (inch)	Greater than 10 feet clearance	1 to 4 tree spans per mile	5 to 10 tree spans per mile	11 to 20 tree spans per mile
Grade N	Tree=0	Tree=1	Tree=2	Tree=3
0	0	0	0	0
0.25	0.00125	0.0025	0.00375	0.005
0.5	0.00375	0.0075	0.01125	0.015
1	0.01375	0.0275	0.04125	0.055
3	0.08042	0.16084	0.24126	0.32168
Grade C	Tree=0	Tree=1	Tree=2	Tree=2
0	0	0	0	0
0.25	0.00013	0.00026	0.00039	0.00052
0.5	0.00038	0.00076	0.00114	0.00152
1	0.00163	0.00326	0.00489	0.00652
3	0.0083	0.0166	0.0249	0.0332
Grade B	Tree=0	Tree=1	Tree=2	Tree=2
0	0	0	0	0
0.25	0.00004	0.00008	0.00012	0.00016
0.5	0.00012	0.00024	0.00036	0.00048
1	0.00054	0.00108	0.00162	0.00216
3	0.00276	0.00552	0.00828	0.01104

The pole failure probability was then used to calculate an average number of failed poles for the MP_A scenario. The number of failed poles was in turn used to determine the number of failures for the other system components. Appendix A provides the equations and assumptions used in this calculation.

4.2.3   Determine Time for System Restoration for MP_A Scenario

The final step in the damage analysis was determining how long it would take to restore power. Using average repair time estimates for each type of component (based on FEMA, 2003), the total repair time for the damaged components was calculated. Then, the number of available linemen was determined, either from local records or based on a regional average. For the projects in this study, the rate of 7 linemen per 4,800 customers was used; this rate was based on the reported availability of linemen for the North Central Power District. The assumption was made that each lineman could work 12 hour days until all repairs were completed and all linemen could work in parallel. This information was used to determine a final time to power restoration.

To determine how this power outage impacted customers, a power restoration curve was required. In cases when the project impacts transmission lines (assumed for all three projects in this study), all repairs must be completed before any customers will receive power. For other cases, when a project is primarily concerned with local distribution lines, the restoration of power will depend on the arrangement of the lines. Some default curves for these types of

systems are available in *Ice Storm of 2002: Four rural electric cooperatives in Kansas* (FEMA, 2003).

Table 4.4 summarizes the results from this step of the damage analysis.

Table 4.4: Damage Analysis Results Summary

Project	MP$_A$ Pole Probability of failure (%)	Total Repair Time for all damaged components (hours)	Number of linemen available	Time to power restoration (hours)	Power Restoration Curve
HMGP-1027-0029 (SWPPD)	0.4%	11	21	1.0	Assume no power until all repairs complete
HMGP-1517-0002 (NPPD)	0.9%	91	35	5.2	Assume no power until all repairs complete
HMGP-1402-0011 (Kiowa)	1.5%	3	2	3.8	Assume no power until all repairs complete

5. SECTION FIVE   LOSS AVOIDANCE ANALYSIS PHASE 3 – LOSS ESTIMATION ANALYSIS

Phase 3 – Loss Estimation Analysis, the final phase of a loss avoidance study, is conducted to estimate the avoided losses based on the effectiveness of the mitigation project during the storm event of interest[4]. The Loss Estimation Analysis is accomplished by calculating the damage (in dollars) associated with the damage analysis calculated in Phase 2.

Phase 3 includes two major tasks:

1. Calculating losses avoided

2. Calculating Return On Investment (ROI)

5.1   CALCULATING LOSSES AVOIDED

Calculating losses avoided requires knowledge of damages for the MP_A and MP_C scenarios. For Phase 3, the loss avoidance analyst must determine the dollar value estimate of the damage that would have occurred had the mitigation project not been built (MP_A) and the damages (in dollars) that did occur after construction of the project (MP_C). The losses avoided (in dollars) are calculated by subtracting the MP_C scenario damages from the estimated MP_A scenario damages. The end result of the loss calculations will be an estimated loss value for the event that actually occurred.

Figure 5.1 illustrates the formula used to compute losses avoided.

> **LOSS ESTIMATION ANALYSIS**
>
> $$MP_A - MP_C = LA$$
>
> Where MP_A = Mitigation Project Absent
> Where MP_C = Mitigation Project Completed
> Where LA = Losses Avoided

Figure 5.1: Calculation of Losses Avoided (FEMA, 2007a)

When calculating losses, it is important to note that all of the losses should be calculated in present-day values. Therefore, if historical losses or adjustment factors are used as estimates, they should be adjusted to present-day values. The following subsections describe various types of losses/damages and how these losses can be designated by dollar values.

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[4] The Loss Estimation Analysis process is very similar for all LAS, regardless of the type of hazard and mitigation measures that are being analyzed. The text and graphics in Section 5 of this report are modified from the FEMA 2007 report titled *Loss Avoidance Study: Southern California Flood Control Mitigation. Part Two: Detailed Methodology*, EMW-2000-CO-0247 HMTAP Task Order 393).

5.1.1 Loss Categories

Once the damage analysis is complete, potential losses need to be evaluated. Table 5.1 identifies the loss categories for potential damages. Loss categories generally include physical damage, loss of function, and emergency management costs, each of which have multiple loss types.

Table 5.1:
Loss Categories and Types

Loss Category	Loss Type
Physical Damage	Structure Contents Roads and Bridges Infrastructure Landscaping Environmental Impacts Vehicles/Equipment
Loss of Function	Displacement Costs Disruption Time for Residents Loss of Rental Income Lost Wages Loss of Business Income Loss of Public Services Economic Impact of Loss of Utilities Economic Impact of Road/Bridge Closure
Emergency Management	Debris Cleanup Governmental Expense

Knowing the loss category and type helps the loss avoidance analyst determine how the potential damages should be calculated. For many of the loss types identified in Table 5.1, standard methodologies and values have been developed. One source of these methods is the FEMA Benefit-Cost Analysis (BCA) Modules. These were developed to standardize determinations of cost-effectiveness for mitigation projects and include damage curves for determining damage based on the severity of an event. These modules and their associated guidance documentation can be adapted for use during loss avoidance studies (FEMA, 2006b). Another source used for methods is the HAZUS-MH model (FEMA, 2006c).

The FEMA benefit cost analysis document, *What Is a Benefit?* (FEMA, 2001)*,* also includes a discussion on calculation of injuries and deaths causes by hazards. For many hazards, FEMA BCA policy has been to not include these benefits, because of sufficient warning times for events. The exception to this is for tornadoes, which have short warning times and where mitigation measures are used specifically to avoid injuries and deaths. For ice and wind storm mitigation, there is insufficient information to justify including these types of benefits. Deaths and injuries do occur from electric system failures during ice and wind storms, especially to linemen and repair crews. However, little information is currently known about the specific

causes of injury and death and how mitigation might prevent these causes. Therefore, these types of avoided losses are not included in this study.

5.1.2   Physical Damage Costs

Physical damages include impacts to structures (residential, commercial, industrial, and municipal); the contents and landscaping for those structures; roads, bridges, and infrastructure; the environment; and vehicles and equipment. The types of physical damages resulting from an event will vary based on the land uses in the project area. When available, actual repair costs should be used to estimate losses, if similar events have occurred in the past. If this information is not available, then the losses must be estimated. Additionally, for events in which the President declared a disaster, FEMA may have provided grant funds under the Public Assistance (PA) Program for repairs by public entities and certain private non-profit organizations. Damage and repair information may be obtained from Project Worksheets (PWs) that FEMA prepared to document eligible costs under the PA Program.

For electric system mitigation projects, repair cost estimates per pole were $5,412 in 2003 dollars (FEMA, 2003) or $6,099 in 2007 dollars. This value is based on historic repair costs and accounts for all system component repairs.   Repair costs for each loss avoidance scenario can be obtained similarly by multiplying the number of damaged poles/wires by historic repair costs.

5.1.3   Loss of Function Costs

According to the FEMA benefit-cost analysis document, *What Is a Benefit?*, loss of function impacts are "the losses, costs and direct economic impacts that occur when physical damages are severe enough to interrupt the function of a building or other facility" (FEMA, 2001). Loss of function can vary significantly depending on the building or facility damaged. Methods for estimating loss of function costs are summarized below, but greater detail can be obtained from *What Is a Benefit?*, the HAZUS-MH Technical Manual, U.S. Army Corps of Engineers (USACE), and local agencies and special districts. Typically, methods for estimating loss of function involve calculating a time delay based on the percent damage to an asset, then calculating costs for this delay of function.

The economic impact of a loss of utility service is the economic value assigned when a utility service is unable to operate as a result of an event. Due to the importance of these services, the economic impact of loss of service is generally much greater than the physical damages to the facility. The method to calculate the economic impact of loss of utility services from FEMA's *What Is a Benefit?* is the following:

1.   Determine the type of facility. The loss of public service calculation will vary slightly depending on the type of utility.

2.   Establish the economic impact of each lost day of operation. This value can be expressed as a dollar value per capita per day, or just a dollar value per day. FEMA's *What Is a Benefit?* provides an economic impact value for electricity of $188 in 2001 dollars or $220 in 2007 dollars per person per day of lost service. This value includes the calculated direct effects of loss of electric power on regional economic activity and the calculated economic impacts on residents. Therefore, this typical value is used to represent ALL loss of function costs. For loss avoidance analysis, this same typical value can also be

used, unless local data are available to approximate the costs for each of the loss types listed.

3.   Determine the functional downtime, or the number of lost days the utility service is unavailable due to the event. The downtime can be estimated based on past events or interviews with utility providers.

4.   When necessary, determine the number of people serviced by the utility. Interviews with utility providers can provide information on the number of people serviced by a particular utility. In most instances, only the area serviced by the transmission/distribution line in the study area should be used.

5.   Multiply the economic impact of the loss of public service by the number of lost days (and the number of people serviced by the utility, when appropriate).

Table 5.2 below summarizes the loss of function types that would be expected for electric systems.

Table 5.2: Loss of Function Types Impacted by Power Outages

Loss Type	Power Outage Considerations
Displacement Expense	Possible for prolonged outages if residents need to rent other lodging
Loss of Rental Income	Not likely
Loss of Business Income	Possible if businesses impacted
Lost Wages	Possible if businesses impacted
Disruption Time for Residents	Likely whenever an outage occurs
Loss of Public Services	Likely if outage impacts public facilities
Economic Impact of Utility Loss	Likely whenever an outage occurs
Economic Impact of Road Closures	Not likely unless excessive downed lines over roads

5.1.4   Emergency Management Costs

The benefit-cost analysis method presented in the report, *Ice Storm of 2002: Four rural electric cooperatives in Kansas* (FEMA, 2003), does not calculate any additional emergency management costs. These costs would typically consider the extra costs required to respond to a disaster. However, the repair cost values used in that report take these costs into account. Separate emergency management costs can be calculated when historical data are available that provide sufficient detail on all components of the costs for electric system repairs. This would include loss types such as employee overtime, design and engineering costs for repairs, debris cleanup, and police costs for traffic control associated with repair operations.

5.1.5 Losses Avoided Results

Table 5.3 summarizes the avoided losses for the three selected projects.

Table 5.3: Loss Estimation Analysis Results (2007 dollars)

Project	Results by Loss Category			Losses Avoided Total
	MP$_A$ Scenario Damages		MP$_C$ Scenario Damages	
	Physical Damages	**Loss of Function**	**All Categories**	
HMGP-1027-0029 (SWPPD)	$4,529	$134,673	$0	$139,202
HMGP-1517-0002 (NPPD)	$37,463	$1,098,197	$0	$1,135,660
HMGP-1402-0011 (Kiowa)	$823	$34,386	$0	$35,209
TOTAL:	**$42,815**	**$1,267,256**	**$0**	**$1,310,071**

NPPD (HMGP-1517-0002) had the highest avoided loss, based primarily on the avoided loss of function to the 23,000 customers impacted by the estimated MP$_A$ 5.2-hour power outage. Loss of function damages were almost 97% of the overall total damages.

5.2 CALCULATING RETURN ON INVESTMENT

The final task in determining losses avoided is to calculate the ROI. The methodology and results may vary depending upon the number of events being analyzed for each mitigation project and the level of damage sustained during each impacting event. Figure 5.2 illustrates the general formula used to calculate ROI.

RETURN ON MITIGATION INVESTMENT

$$\frac{\$\ LA}{\$\ PI} = \%\ ROI$$

Where LA = Losses Avoided
Where PI = Project Investment
Where ROI = Return on Investment

Figure 5.2: ROI Calculation

The bottom portion of the equation (PI) is the total project investment for the mitigation project being evaluated. Project investment does not represent the Federal investment alone, but rather the resource investment from all parties involved. The project investment should represent the costs of the project components being evaluated in the loss avoidance study, and should not include work conducted outside of the mitigation project scope.

The upper portion of the equation (LA) is the total losses avoided for the mitigation project being evaluated. If the loss avoidance study is evaluating one event of interest, then the losses avoided and resulting ROI would represent one discrete event. However, if multiple events are being evaluated for each mitigation project, then the LA would represent the total losses avoided for all the storm events evaluated. Therefore, the ROI would represent the return on investment for the project over several storm events.

5.2.1 ROI Results

Table 5.4 compares losses avoided for each project with the final project costs converted to 2007 dollars.

For the three projects, the ROI ranged from 0.1 to 4.72. The ROI for all three projects combined was 1.14. The ROI values calculated for this study reflect the losses avoided for only one event of interest; therefore, ROIs will increase as additional storm events test each project's effectiveness.

Table 5.4: Return on Investment Results (2007 dollars)

Project	Results by Loss Category		Total Losses Avoided	Project Investment	Current ROI
	Physical Damages	**Loss of Function**			
HMGP-1027-0029 (SWPPD)	$4,529	$134,673	$139,202	$556,358	0.25
HMGP-1517-0002 (NPPD)	$37,463	$1,098,197	$1,135,660	$240,665	4.72
HMGP-1402-0011 (Kiowa)	$823	$34,386	$35,209	$355,616	0.10
TOTAL:	**$42,815**	**$1,267,256**	**$1,310,071**	**$1,152,639**	**1.14**

6. SECTION SIX   CONSIDERATIONS AND RECOMMENDED PRACTICES

This is the first loss avoidance study on a non-flood hazard event and the first study for a specific type of asset, specifically electrical systems. While the general process of conducting an LAS was adapted from past flood LASs, much of this study was brand new and many practices were identified that will improve future studies. These practices and lessons learned can be grouped into two broad categories related to data and analysis. These suggested practices would provide improvements based on the lessons learned from this LAS study in Nebraska and Kansas. Adoption of these recommendations would establish a strong basis for future studies on electric systems and other utility systems with similar distribution networks.

6.1   DATA

6.1.1   Project Data

Electric system mitigation projects tend to cover large areas, some in the tens or hundreds of square miles. Therefore, having project descriptions with detailed mapping of the project locations is critical to the success of an LAS. Obtaining clear descriptions of the phases of large projects and what phases and/or components were completed prior to an event of interest is also important. For example, the NPPD (HMGP-1517-0002) project has five different phases, with only one completed prior to the 2006 event. Understanding what was constructed and when it was constructed is important when developing the potential project list, because the list should only contain locations affected by the event of interest.

6.1.2   Ice and Wind Storm Severity

The intersection of project location and event location is a primary aim when looking at potential projects for an LAS. As seen in this study, the details of the affected area may not be readily apparent. Unlike many other types of natural hazards, winter storms tend to affect large areas with a wide range of local variability. While a flood has a floodplain and a tornado has a damage path, ice storm severity can be widespread across the landscape. The initial project and final project selection was conducted prior to the release of a detailed study (Jones, 2007) that contained event severity estimates at the local level. All three project sites turned out to be on the fringe of the area affected with the greatest ice accumulation levels and not in the "heart" of it.

The issue of determining the severity of the event of interest at the project sites has several aspects. Ideally, a direct measurement of the storm levels (ice radius, maximum wind speeds) would be obtained from local officials. However, this often may not be possible. Official weather stations tend to be fairly widespread and conversations with local officials often provide only generalized information such as, "Ice levels were pretty low in some places and up to an inch or more in other places." The lack of local detail will often require some sort of modeling by experts to come up with maps like Figure 2.1.

One future practice recommendation based on these issues is to coordinate with local, State, and Federal groups—for example, the USACE CRREL—to determine what kinds of storm severity data are available and if any sort of event modeling is underway. This coordination may require

LAS schedules to have extended data collection timeframes to allow completion of this modeling prior to the final project selection process. The other suggested future practice is that some process should be established to monitor completed mitigation projects and their responses during events, including damages and/or ice and wind levels experienced.

6.2   ANALYSIS

6.2.1   Historic Damage Data

When a BCA is conducted for electric system mitigation projects, often the benefit calculations use the actual damages from past events. This same information can be used for an LAS, as long as the event of interest can be tied to a certain recurrence interval. The damage analysis used in this report was required because limited historical damage information was available and the event severity in all three locations was too low to correlate with the historical data. In addition, the assignment of a recurrence interval to a particular event can be problematic, since most sources, such as the American Society of Civil Engineer's *Minimum Design Loads for Buildings and Other Structures*, ASCE Standard 7-05 (ASCE 7, 2005), are based on a specific ice level and wind speed. When actual wind speeds exceed the design limits, the process for determining an equivalent radial ice level can be complicated. Therefore, a suggested future practice for LASs is to use historical damage data when appropriate.

6.2.2   Damage Analysis Method

The methods used in this LAS are one way to estimate damages from different ice levels for the particular NESC electrical system grades. As with many models, this initial method could be improved in several ways. One important improvement would be to have ice and electric system modeling experts evaluate the methods and provide refinements based on the latest research. A similar process is currently being used for the redesign of the FEMA BCA modules for other natural hazards (floods, tornadoes, etc.). Another improvement would be to clearly define how to represent different types of projects in the model. For example, for the NPPD (HMGP-1517-0002) project, the BCA was used to develop the "pole-equivalent" for this project. A formula-based adjustment, taking into account the dead-end structure design and the grade of the remaining poles between the structures, would provide a better estimate for this type of project.

Another practice improvement would be to incorporate updated values for some of the "defaults" used in this method, such as the average pole and components repair cost and the average customer cost per day for a power outage. These defaults could be updated for different regions of the U.S. and/or given more detail for different types of customers, such as commercial and industrial customers.

7. SECTION SEVEN   REFERENCES

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General Resources

FEMA Flood Insurance Studies and Map Revision Files:
        http://msc.fema.gov/

FEMA Hazard Mitigation Grant Program:
        http://www.fema.gov/government/grant/hmgp/

FEMA Public Assistance Program:
        http://www.fema.gov/government/grant/pa/index.shtm

Minnesota Department of Public Safety-Division of Emergency Management:
        http://www.hsem.state.mn.us/uploadedfile/success_stories.pdf

USACE Cold Regions:
        http://www.crrel.usace.army.mil

Appendix A

Ice and Wind Loss Avoidance Analysis Damage Analysis Method

APPENDIX A ICE AND WIND LOSS AVOIDANCE ANALYSIS DAMAGE ANALYSIS METHOD

A.1 METHOD OVERVIEW

The damage analysis used in this LAS was based on a benefit-cost analysis (BCA) method developed in the report titled *Ice Storm of 2002: Four rural electric cooperatives in Kansas* (FEMA, 2003). The main difference between the BCA and LAS methods is not in the damage analysis, but in how the results are used to calculate benefits versus losses avoided.

The three major steps of the damage analysis are:

1. Collect project data

2. Determine system failures for MP_A scenario

3. Determine the time for system restoration for MP_A scenario

A.2 COLLECT PROJECT DATA

The minimum data requirements for conducting a loss avoidance analysis for an electric system mitigation project are shown in Table A.1 (shown earlier in Table 4.1).

Table A.1: Project Data Requirements

Data Requirement	Description
MP_A System Design	Information about the electric system for the MP_A scenarios, including: • NESC System Grade (N, C, B) • Urban or Rural Setting • Tree Cover
Mitigation Project Design	Information about the mitigation project, including: • Project location and design (including miles of improvements or number of poles and NESC Grade of improvements) • Population impacted by project • Project Cost
Storm Event Information	Information about the ice and wind event of interest, including: • Radial ice equivalent for project location • Actual damages (dollars) to project location

MP_A System Design

The NESC System Grade can usually be assumed to be NESC Grade N for all older systems and Grade C or B for all new improvements.

The tree cover levels are defined as follows (FEMA, 2003):

- Tree = 0 (tree clearance exceeds 10 feet at all locations). This would be common in areas with no trees or for areas with a superior tree-trimming program.

- Tree = 1 (tree clearance may be less than 10 feet at some locations, from 1 to 4 spans per mile of circuit).

- Tree = 2 (tree clearance may be less than 10 feet at some locations, from 5 to 10 spans per mile of circuit).

- Tree = 3 (tree clearance may be less than 10 feet at some locations, from 11 to 20 spans per mile of circuit).

Mitigation Project Design

These data are important to determine where the mitigation project was installed and how the customers are connected to the system. Initially, the extents of the mitigation project (showing the location of the improvements) need to be determined. For projects where a series of poles and/or wires are completely replaced, the extent of the project is fairly easy to identify. For projects like installation of dead-end structures, some analysis may be needed to determine which portions of an electric system are protected by a project.

If the mitigation project focused on transmission lines, then any damage would be expected to cause power outages to all customers. Distribution line projects have a different power restoration curve, where repairs are typically prioritized so more customers have their power restored earlier and a small number of outlying customers have to wait the entire restoration time.

Finally, the base year that the mitigation project costs were incurred, typically when the project was constructed, needs to be noted so the costs can be adjusted to current values.

Storm Event Information

Gathering adequate and accurate storm even information can be challenging. The key need is to find the amount of radial ice equivalent experienced in the mitigation project location. Ideally, this would be directly measured by the local electric utility company or at a local weather station. Local officials can also provide this information, although data received from local officials may not be as precise as data from "official" sources. As noted earlier, State and Federal organizations, such as the USACE CRREL, may also produce reports with regional radial ice equivalent values that take into account both the measured ice levels and wind loads.

Some portions of a specific project may be eliminated from the analysis if the storm of interest produced little or no ice build-up. In most cases, the intersection of the project extent and the storm event extent should be used in Phase 1 to develop the initial project list before any additional Phase 2 analysis is conducted.

Another consideration is those system components that actually failed during the event of interest. Because the basic assumption is that the electrical system is "stronger" in the MP_C scenario (as compared with the MP_A scenario), one can reasonably assume that any MP_C system component that failed during the event of interest would have failed in the MP_A scenario. Therefore, these system components can be removed from the analysis, unless there is a

difference in the cost of repair or associated loss of function between the two scenarios for those components.

A.3   DAMAGE ANALYSIS

This includes both the determination of system failures and the time for system restoration for the MP_A scenario, which were listed separately in Section 4. The following steps have been slightly modified from the method listed in the report titled *Ice Storm of 2002: Four Rural Electric Cooperatives in Kansas* (FEMA, 2003) based on local values:

1. Estimate the miles of circuit in Grades N, C, or B, and subdivide by ice loading and tree cover. The assumption can be made that total poles can be estimated as 18 poles per mile in rural areas or 36 per mile in urban areas (FEMA, 2003). As mentioned earlier, for the NPPD project, the benefit cost analysis for the dead-end structures indicated that damages are reduced by 2/3. Therefore, the equivalent poles and miles are 2/3 of the total length of 58.4 miles or 39 miles. For other dead-end projects, the benefit costs analysis results should be used to determine the level of protection estimated for the project.

2. Use Table A.2 to determine failure probability for each unique combination of ice, grade, and tree cover. This will estimate the extent of component damage, p, using the median factors. Ideally, the radial ice amounts for the event of interest should come from local sources or reliable sources such as the USACE CRREL. When these are not available, the ice storm maps in ASCE 7 that give 50-, 100-, 200-, and 400-year frequency values may be used to determine an approximate ice amount, if a recurrence interval can be assumed. The values in Table A.2 may increase or decrease if the actual winds exceed or are lower than the assumed concurrent winds shown in the ice-loading maps. Values may be interpolated linearly for intermediate

Table A.2: Pole Failure Probability, P

Radial Ice (inch)	Tree=0	Tree=1	Tree=2	Tree=3
Grade N				
0	0	0	0	0
0.25	0.00125	0.0025	0.00375	0.005
0.5	0.00375	0.0075	0.01125	0.015
1	0.01375	0.0275	0.04125	0.055
3	0.08042	0.16084	0.24126	0.32168
Grade C	Tree=0	Tree=1	Tree=2	Tree=2
0	0	0	0	0
0.25	0.00013	0.00026	0.00039	0.00052
0.5	0.00038	0.00076	0.00114	0.00152
1	0.00163	0.00326	0.00489	0.00652
3	0.0083	0.0166	0.0249	0.0332
Grade B	Tree=0	Tree=1	Tree=2	Tree=2
0	0	0	0	0
0.25	0.00004	0.00008	0.00012	0.00016
0.5	0.00012	0.00024	0.00036	0.00048
1	0.00054	0.00108	0.00162	0.00216
3	0.00276	0.00552	0.00828	0.01104

Notes:
Radial ice = r (inches)
P = Probability of failure (0 to 1)
Tree cover levels were defined in the previous section.

amounts of radial ice. Grades C and B are for designing to NESC 2002 for "heavy" ice loading.

3.   Estimate the number of components damaged using the following factors (FEMA, 2003):

- Number of poles damaged. N = Poles damaged in rural areas = p * total poles. N = Poles damaged in urban areas = 0.25 * p * total poles.

- Number of wires damaged. Wires damaged in rural areas W = N * 3. Wires damaged in urban areas W = N * 6.

- Number of cross-arms damaged (pole does not require repair) C = N * 0.1.

- Number of guy wires damaged G = N * 0.01.

- Number of pole-mounted transformers to be repaired T = N * 0.2.

If the analysis includes poles that were actually damaged during the event, those numbers should be added to the value calculated for the undamaged poles. All other calculations for damage of other components should then be based on this adjusted value of damaged poles.

During severe ice storms, failure of electric system components may cause additional physical damage when downed poles and wires damage houses, vehicles, or cause fires from short-circuited lines. The best source of information for these damages is historical damages in the location of interest. For example, if a project is primarily in an urban area where past ice storms have caused failed poles to damage vehicles, then this historical information can be used as a basis to estimate vehicle damages for both MP_A and MP_C scenarios.

4.   Estimate the repair effort (hours by linemen in the field) using the following factors:

- H = N*8 + W*2 + C*4 + G*4 + T*2

5.   Estimate the number of linemen available to make repairs (use utility-specific data if available):

- L = population served * 0.005 (round up) (FEMA, 2003).

- L = population served * 0.015 (round up): This value was used for this LAS. It is based the North Central Power District in Nebraska that has 7 linemen for every 4,800 customers.

6.   Estimate the number of linemen from mutual aid to make repairs (requires iteration with Step 7):

- M = 0 if D100 < 2 days

- M = L if D100 is 2 to 5 days

- M = 2*L if D100 is 5 to 10 days

For any given ice storm, the loss of service time for any given customer depends on the extent of damage (i.e., number of downed lines and poles), on the availability of resources (repair crews, materials, equipment), and on management decisions about service restoration priorities. Obviously, the greater the extent of damages, the longer it takes (total repair crew hours) to restore service completely. In small ice storm events, utilities generally repair damage with their

own crews. In large events, local utility repairs crews are supplemented with additional mutual aid crews from other utilities not affected by the ice storm event.

7.   Estimate the number of days until 100% service is restored. Note: This model assumes linemen are working 12 hours per day, 7 days per week, until all service is restored.

- $D100 = H /\{12*(L+M)\}$

8.   Estimate the percentage of customers that lose power due to the ice storm. This percentage relates to the time immediately after the bulk of the ice- and wind-related damage occurs.

- Refined method. Assume the entire customer base on that circuit is out of service. Do this for all circuits in the system.

- Simplified method. Assume that the ice storm impacts the entire electric system more-or-less uniformly. For larger ice storms, this is essentially true. For smaller ice storms this is not true, and distribution of damage is accounted for using an area adjustment factor. For this computation, p = system-wide percentage of pole damage.

   - $S = 0.05$ for $p > 0.005$

   - $S = 0.25$ for $0.003 < p <= 0.005$

   - $S = 0.50$ for $0.0015 < p <= 0.003$

   - $S = 0.90$ for $0.0002 < p <= 0.0015$

   - $S = 0.95$ for $0.00005 < p <= 0.0002$

   - $S = 0.98$ for $0.00001 < p <= 0.00005$

- Example: If system-wide $p = 0.00006$, then service ratio $S = 0.98$ (98%).

- Adjustment for small ice storms (not affecting the entire service area): If area with radial ice > 0.1 inch is $A = 0.30$ (30%) of the total system area, then assume that 80% of the remaining unaffected area has no ice-loading damage. Then S (small storm) = $\{1.25*A (<1.00)\} * S$.

9.   Estimate the service restoration curve.

This depends on whether the system is redundant (2 feeds per customer or a circuit with 2 or more air switches) or non-redundant (customer is on a circuit with a single feed and no air disconnect switches).

- Redundant system.

   - $D50 = D100 * 0.25$

   - $D75 = D100 * 0.50$

   - $D90 = D100 * 0.75$

- Non-Redundant system (assumption for this LAS)

   - $D50 = D100 * 0.50$

   - $D75 = D100 * 0.75$

- $D90 = D100 * 0.90$

In repairing ice storm damages, utilities generally attempt to restore service to as many customers as possible, as quickly as possible. Thus, repairs are prioritized according to the specific damage pattern and the operating characteristics of each system. Repairs to trunk lines serving large numbers of customers and repairs to links allowing alternative sources of power are usually prioritized. Customers near the end of lines serving few customers will usually experience the longest service outage times.

Thus, a typical service restoration pattern is that many or even most customers who lose power have service restored quickly, typically within a few hours to 24 hours. Then, service is gradually restored to other customers. However, especially for rural electric systems with many miles of distribution lines and a very low density of customers, final service restoration to the last few customers may take several days or even as long as several weeks in major ice storm events.

A.4   LOSS AVOIDANCE ANALYSIS COMMENTS

Section 5 provides details on how to take the results of the damage analysis and calculate avoided losses. For this LAS, all physical damages per pole were assumed to be $5,412 in 2003 dollars or $6,099 in 2007 dollars, which accounts for repair of all system components associated with a pole failure (FEMA, 2003). All loss of function damages were assumed to be $188 in 2001 dollars or $220 in 2007 dollars per person per day of lost service, based on FEMA BCA publications. Both of these defaults should be based on local data when available.