EDISON ELECTRIC INSTITUTE

Out of Sight, Out of Mind Revisited

An Updated Study on the Undergrounding Of Overhead Power Lines

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Executive Summary

It is almost a given fact that following a major hurricane or large ice storm the affected utilities, customers, and state public utility commissions will commence an ongoing discussion regarding the customer's desire to migrate from an overhead to an underground electrical infrastructure. There are many pros and cons for making this transition. In some cases, the desire for undergrounding is driven by utility needs; in other cases, it is a request spearheaded by customers. In either case, undergrounding the system has implications for the reliability, costs, and aesthetics of the electrical system.

Over the last 10 years, at least 11 state studies or reports have been generated due to the outage impact of unusually large storms. One of the main focuses of each of these reports has been the investigation into undergrounding of the electric utility's infrastructure with the desire to improve the reliability and availability of electric service during and after major storms. Even when storms are not causing havoc on the electric utility infrastructure, there are many communities that express the desire to improve the aesthetics of their streets and roadways by undergrounding all utilities. Yet to date, no state utility commission has recommended wholesale undergrounding of the utility infrastructure.

In this third edition of the *Out of Sight, Out of Mind* report, the Edison Electric Institute has sought to present and investigate new information that has not been explored by other studies. This report has examined the previous six years of major storm events to determine what trends and impact these events are having on the industry. This report has investigated reliability data from large investor-owned owned utilities to determine what type of reliability advantage that undergrounding may provide to customers. Information has been gathered pertaining to the miles-of-line of overhead, underground facilities, and utility expenditures on new construction. This report has also collected construction and conversion cost estimates from utilities to provide a range of costs for communities interested in placing their utilities underground.

Available reliability data demonstrates that major storms can have a significant negative impact on the reliability of the electric system. This negative impact has been the catalyst of every state undergrounding study. However, available reliability data also indicates that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems. Regardless, every year, for the last 10 years, utilities working with communities and customers have committed at least 25% of new distribution construction dollars toward the building of underground.

The most significant obstacle to undergrounding utility infrastructure is the high costs of making these conversions. Currently, new underground distribution construction and overhead to underground conversions cost five to ten times more than comparable overhead construction. But utilities continue to support undergrounding. Nearly all new residential and commercial developments in the United States are served with underground electrical facilities. And there are a few states and utilities that have developed policies and procedures designed to encourage the utility and the local municipality to work together to convert select overhead areas to underground. In these cases, the municipality may be able to defray some of the conversion costs or the utility is allowed to add the conversion cost to the rate base for the customers within that municipal district.

The future of undergrounding will continue to hinge on the ability of customers and the utilities to work together to reach a compromise on meeting customer expectations and compensating utilities for the cost of placing electrical facilities underground.

Chapter 1: Customer Expectations

Economic viability and meeting customer expectations are two of the principal requirements for any sustained business venture. Customer expectations and desires have helped guide the development of the electric utility industry from its beginning in Thomas Edison's workshop to the vast network of cables and wires that currently comprise the modern electrical grid. During the development of the electrical grid, the priorities for electric customers have shaped the development of the industry. These issues include: reliability of electrical service, public safety, cost of service, and electrical system aesthetics. These issues have presented challenges and opportunities for electric utilities as they have sought to balance customer expectations with providing reliable electrical service at a reasonable price.

One ongoing topic of discussion in the utility-customer relationship is the desire to migrate from an overhead to an underground electrical infrastructure. There are pros and cons for making this transition. In some cases, the desire for undergrounding is driven by utility needs; in other cases, it is a request spearheaded by customers. In either case, undergrounding the system has implications for the reliability, safety, cost, and aesthetics of the system. Some of these factors will be addressed in greater detail later in the paper, but for now we will discuss some of the customer driven reasons for undergrounding.

Reliability

Improved system reliability via undergrounding electric utilities has become somewhat of an urban legend; many customers assume that by placing electric lines underground all electrical interruptions cease. It is true that underground lines are not prone to many of the typical overhead outage causes, but underground electrical systems do have their share of outage causing events that are unique to underground systems. Chapter 3 will discuss the impact placing lines underground has on the overall reliability of the system and investigate available reliability data comparing overhead and underground systems. Section 5.2 will discuss the types of inherent reliability issues underground facilities contribute to the grid.

Safety

Installing and/or relocating electrical facilities to an underground configuration will decrease the potential of electrocution, but it will not completely eliminate this possibility. A 2002 Centers for Disease Control and Prevention paper, *Trends in Electrical Injury*, explored the causes of fatal and non-fatal electrical injuries for utility workers for the years from 1992 to 2002. The number of fatalities during that 11-year period caused by contact with overhead power lines was 1,432, whereas the fatalities for contact with buried power cables were 35. Meanwhile, the number of non-fatal injuries during this same time caused by contact with overhead power lines during this time was 1,665 and injuries from contact with buried power cables was 753. Although the available data focused on utility workforce injuries, the general public is also prone to some of these types of electrical injuries. It is common to hear reports of utility customers coming in contact with an overhead power line or digging into an underground power line in their yard.

Undergrounding Costs

The cost of placing electrical facilities underground is a consistent issue of contention between utilities and customers. The costs of installing underground facilities are several times more expensive than that of overhead facilities. To assist with these additional costs, utilities normally seek some type of cost recovery from the customers that desire this change to the electrical system. However, many customers desire these underground facilities to be installed at little or no cost. Chapter 6 will investigate the cost issue as it relates to installing underground facilities and converting to an underground system. Chapter 7 provides summary information regarding how various state commissions have dictated the customer cost contribution for undergrounding.

Aesthetics

Aesthetics is a primary factor in placing lines underground (see Figure 1.1 illustrating New York City in the late 1800's). Most customers today prefer a more natural looking landscape, one that is not framed by wires and poles. To respond to customer concerns, most utilities have policies or procedures that prescribe how and when a utility places facilities underground. Chapter 7 discusses current policies and procedures that utilities are using to address these changes.

Figure 1.1 New York City in the late 1800's

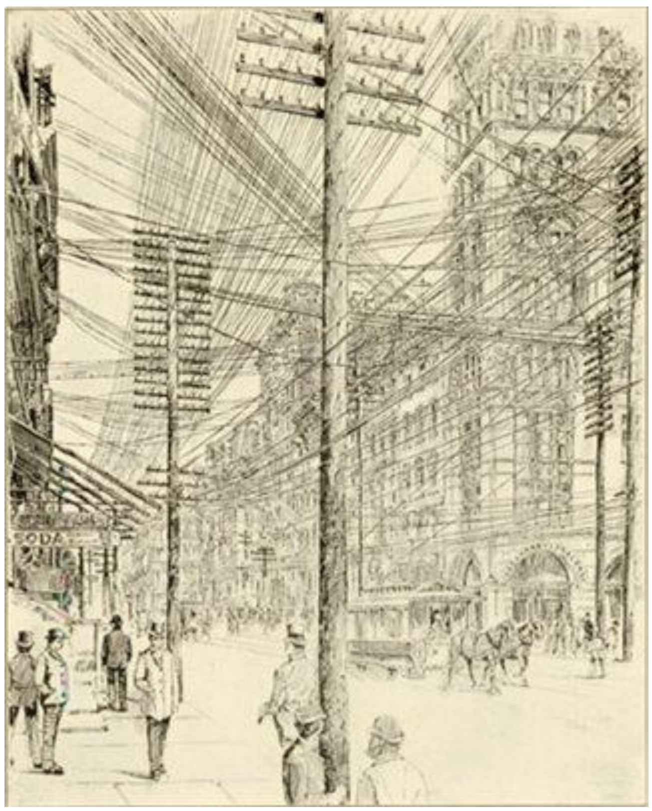


Illustration courtesy of Consolidated Edison, Inc.

Chapter 2: Storms and Outages

Restoring power to all affected customers in the aftermath of a large storm can take several days for most utilities. To expedite the restoration process following most major storms, utilities will bring in thousands of extra lineworkers from other utilities and work around the clock to "get the lights back on." Industry experience has shown that customers are somewhat understanding of the fact that the restoration process takes time, but their tolerance has its limits because outages lasting longer than a day or two are so disruptive to everyday life. After these large events, it has become common for customers, local officials, and even state utility commissions to call for putting some or all of the utility's electrical facilities underground. Table 2.1 lists some of the major storms and the ensuing studies that have been performed in the wake of such storms over the past 10 years.

Table 2.1 Major Storms and Resulting State Studies

Storm	Year	Study
December Ice Storm	2002	2003, November 21 – North Carolina *The Feasibility of Placing Electric Distribution Facilities Underground*, Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force
January Ice Storm/ Hurricane Floyd	1999	2003, December 30 - Maryland *Task Force to Study Moving Overhead Utilities Lines Underground*
Hurricane Isabel	2003	2005, January 7 - Virginia *Placement of Utility Distribution Lines Underground*, Report to the State Corporate Commission
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2007, February 28 - Florida *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion* by Richard Brown, InfraSource Technology
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2007, August 6 - Florida *Undergrounding Assessment Phase 1 Report: Undergrounding Case Studies* by Richard Brown, InfraSource Technology
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2008, May 21 - Florida *Undergrounding Assessment Phase 3 Report: Ex Ante Cost and Benefit Modeling* by Richard Brown, Quanta Technology
December Ice Storm	2007	2008, June 30 - Oklahoma *Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma*, Prepared and Submitted by Oklahoma Corporation Commission Public Utility Division Staff

Storm	Year	Study
Hurricane Ike	2008	2009, April 21 – Houston, Texas *Electric Service Reliability in the Houston Region*, Mayor's Task Force Report

In examining the overhead-underground debate, it is worth investigating and understanding the types of storms that cause major outages to the electrical system. According to the 2008 EEI Reliability Report, 67% of all outage minutes were weather related. The contributing weather related factors from the EEI report are: lightning 6%, weather 31%, and vegetation 30% (which is usually the result of wind blowing vegetation into contact with utility lines). To assist with understanding the impact of weather related outages, this report has analyzed storm data available from the U.S. Department of Energy (DOE).

Storm Data

DOE monitors major system incidents on electric power systems and conducts investigations of significant interruptions of the electric power system. All electrical utilities are required to report large outages using DOE form OE-417 "Electric Emergency Incident and Disturbance Report." An outage must be reported if it meets any of the following criteria:

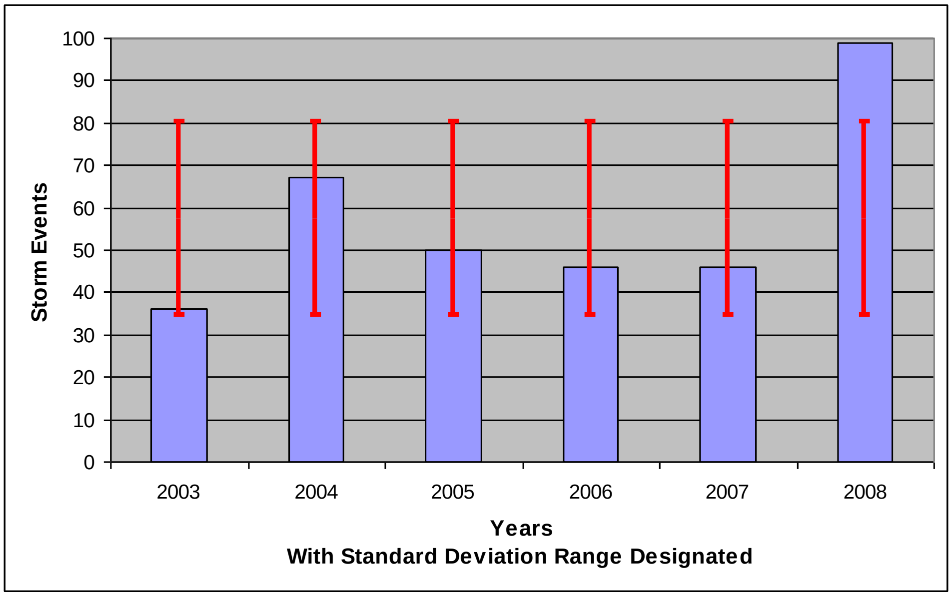
1. Physical attack that causes major interruptions; Actual cyber or communications attack that causes major interruptions of electrical system operations.
2. Complete operational failure or shut-down of the transmission and/or distribution electrical system.
3. Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked-out area or within the partial failure of an integrated electrical system.
4. Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident.
5. Load shedding of 100 Megawatts or more implemented under emergency operational policy.
6. System-wide voltage reductions of 3 percent or more.
7. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
8. Suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism which targets components of any security system.
9. Suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
10. Loss of electric service to more than 50,000 customers for 1 hour or more.
11. Fuel supply emergencies that could impact electric power system adequacy or reliability.

The data collected from form OE-417 is compiled by DOE's statistical agency, Energy Information Administration (EIA), to create publicly available information about electrical system outages. This report has reviewed the available data for years 2003 to 2008 to identify the impact and trends of major weather related outages during that six-year period. As noted above, this data does not include every outage in the U.S., but only events that have had a more sustained impact on customer outages.

We will begin by investigating any trends that may exist in the available outage data. The following four figures provide information on the annual number of events[1], the number of customers impacted, and the number of hours of annual outage.

Figure 2.1 EIA Data – Storm Events – This chart exhibits the number of major weather events for each year. Except for 2008, the number of events per year fall within one standard deviation of ± 23 events, with an average of 57 events per year for all years.

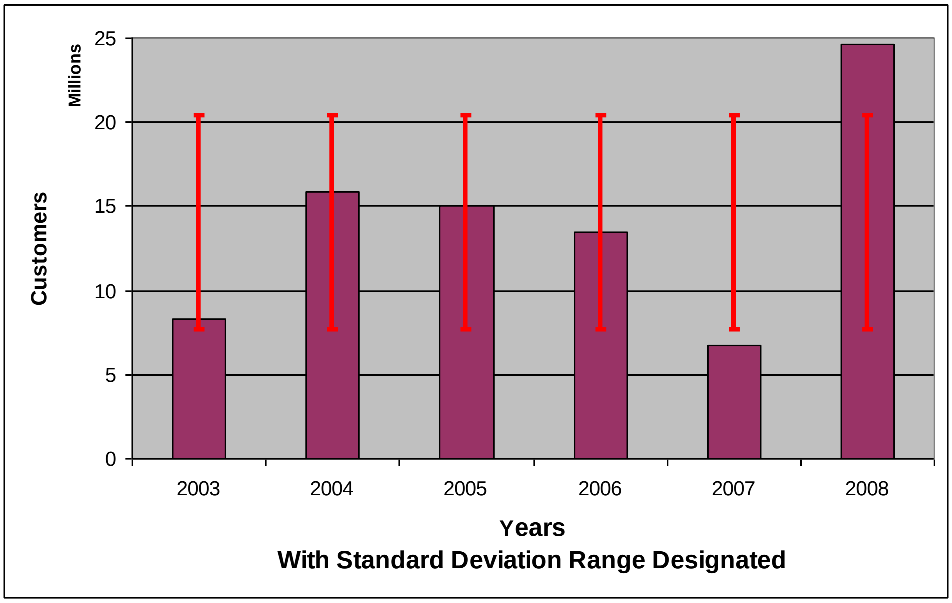
Figure 2.1 EIA Data – Storm Events



[1] A single storm can count for more than one event if it impacts more than one utility. For example, Hurricane Ike (2008) resulted in nine utilities reporting outages to EIA; therefore, Hurricane Ike would account for nine events that year.

<u>Figure 2.2 EIA Data – Customers Affected</u> – This chart exhibits the number of customers experiencing storm event outages annually. The customer outage data per year falls within one standard deviation of ± 6 million customers (except for 2007 and 2008) with an average of 14 million customers for all years.

Figure 2.2 EIA Data – Customers Affected



<u>Figure 2.3 EIA Data – Hours of Interruptions</u> – This chart exhibits the number of annual outage hours. Similar to the Customers Affected chart, the years 2007 and 2008 tend to be outliers. Data for the other years fall within one standard deviation of ± 1,900 hours, with an average of 4,770 hours of interruption for all years.

Figure 2.3 EIA Data – Hours of Interruptions

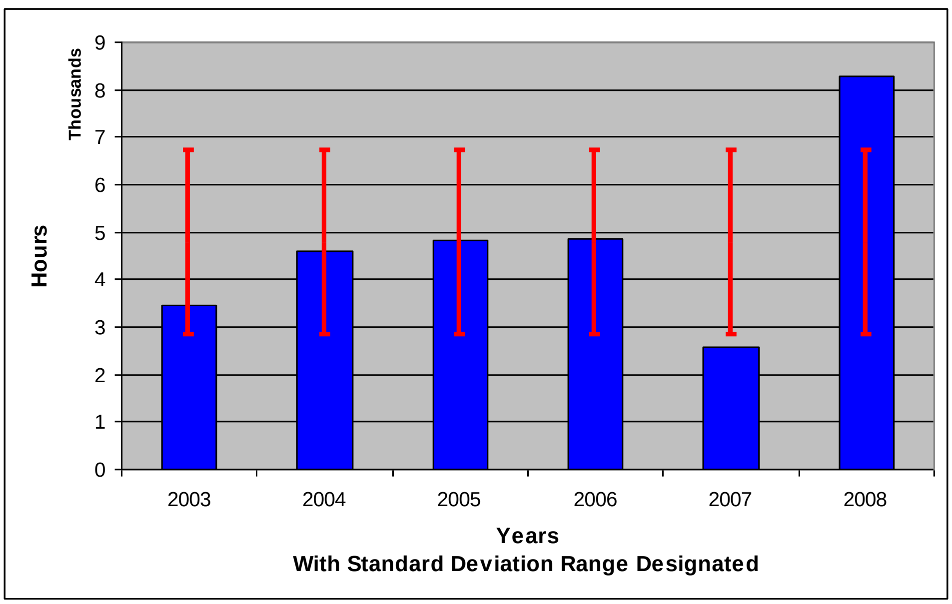
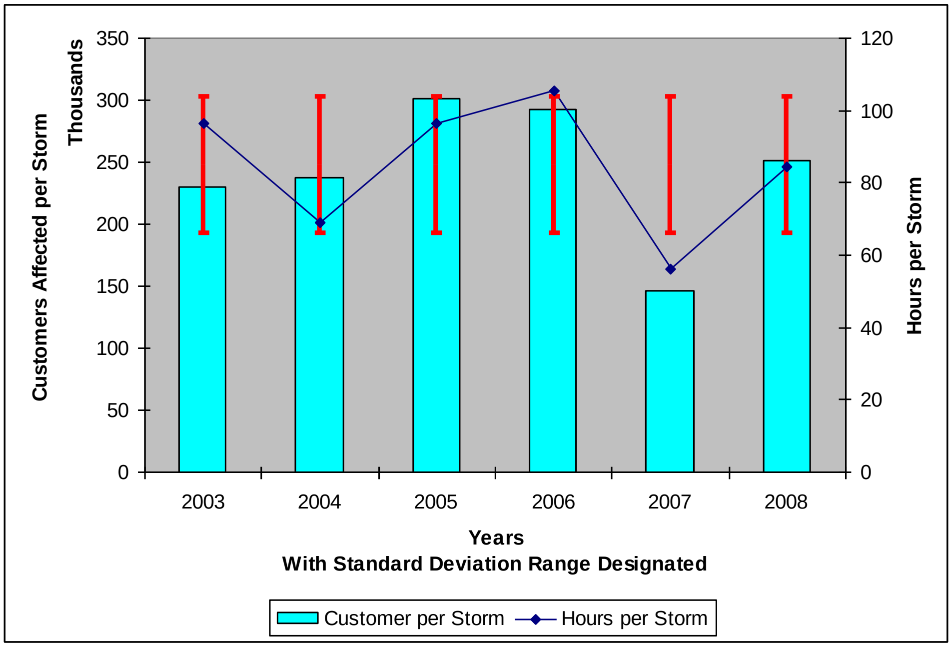


Figure 2.4 EIA Data – Customers Affected per Storm and Hours per Storm – This chart provides a comparison of the average number of customers impacted by each storm and the average length of time to restore service following those storms. In this data set, only 2007 data falls outside of the standard deviation for either customers affected or hours per storm. The average for customers impacted per storm for all years is 242,000 and the average outage time per storm for all years is 84 hours.

Figure 2.4 EIA Data – Customers Affected per Storm and Hours per Storm



The data in charts 2.1 -2.4 does not reveal any trends of increasing or decreasing averages in number of events, length of events, or number of customers impacted by storms. The data appears to show that the annual weather impact to the electrical grid is rather consistent from year to year. Some questions to consider at this point, after reviewing the EIA data for this six-year period:

- How much of an impact do major events have on reliability statistics?
- Do underground facilities help to improve reliability statistics?
- Has the overall percentage of the underground electrical system increased during this time?
- If it has, has it contributed to any major improvement to reliability, according to the outage data available from EIA?

We will investigate what changes have taken place in the quantity of underground facilities in Chapter 4.

Types of Storms

The next several figures will present the categories of storms that are most frequent, that affect the most customers, and that cause the largest number of outage hours. The EIA data captures the “Type of Disturbance” for each outage; however, they have not created a standardized list of disturbances for uniformity in the data. For example, summer storms associated with rain, lightning, wind, and thunder have 47 different types of listings. In an effort to manage the data, this report has assigned each of the events to one of the following seven categories:

- Earthquake
- Flooding
- Heat Storm
- Hurricane/Tropical Storm
- Summer Storm (Lightning/High Winds)
- Wildfire
- Winter Storm (Ice/Snow)

Of these types of events, Hurricanes/Tropical Storms, Summer Storms, and Winter Storms together make up more than 95+% of all the events recorded. This report has included earthquakes, flooding, heat storms, and wildfires in the listing because they are naturally occurring events.

<u>Figure 2.5 Percentages of Storms Types, Customers Out, and Outage Hours</u> - The three charts show the percentage breakdown for the Type of Storms, Total Customers Out, and Total Outage Hours for the summation of all events from 2003 to 2008. The data in the charts is consistent in showing that summer storms are the leading cause of electrical grid outages, followed by hurricane/tropical storms and winter storms. The data also shows that though there are a third fewer hurricane/tropical storms than summer storms, they both have an almost equal impact on the number of customers affected by outages. Again, it is worth reiterating that this data is only for major outage events reported to EIA.

Figure 2.5 Percentages of Storms Types, Customers Out, and Outage Hours

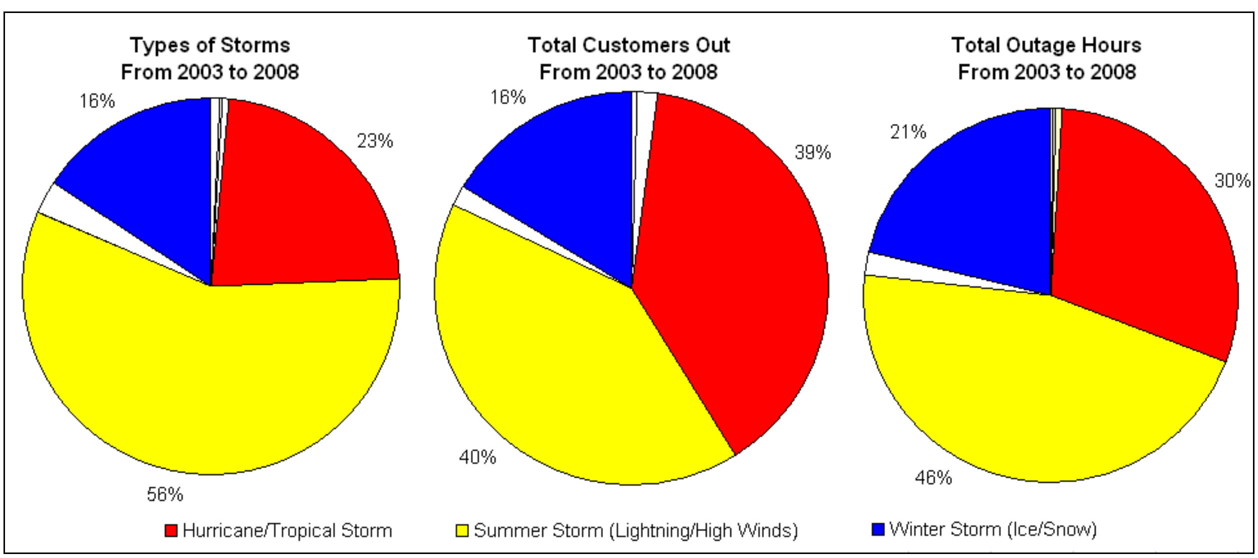
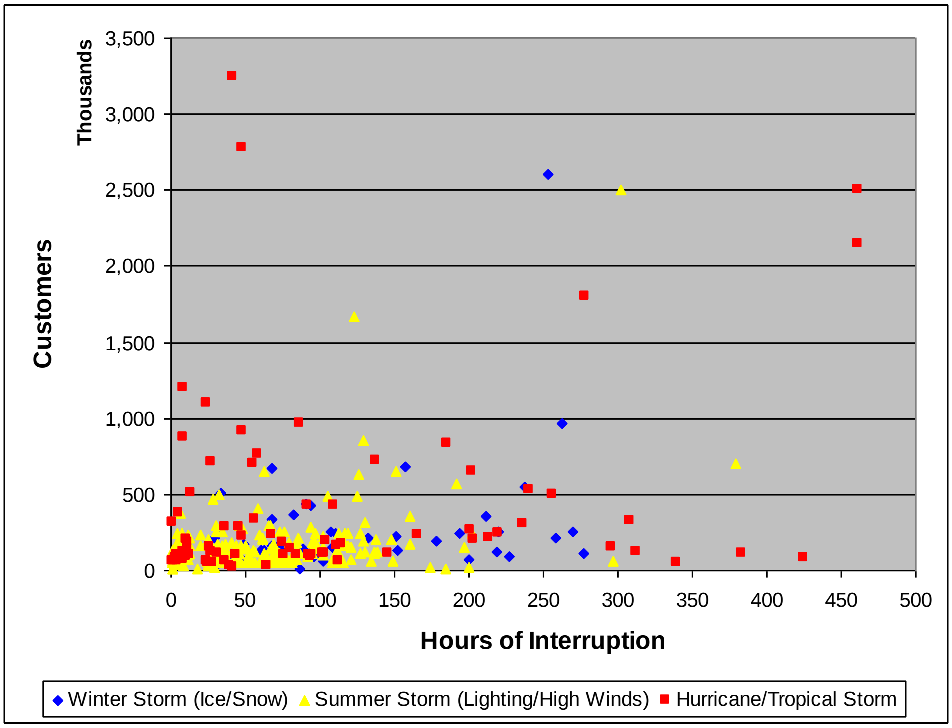


Figure 2.6 Customers vs. Hours – This chart is a scatter plot of the number of customers affected compared to the length of the associated outage. The data confirms that hurricane/tropical storms tend to be the more extreme events, affecting more customers and producing longer outage times. The data also illustrates that winter storms tend to have durations equal or greater than many of the summer storm events.

Figure 2.6 Customers vs. Hours



After analyzing EIA data on major storms over the last six years, it may be deduced that storms that produce strong winds are the major cause of warm weather grid failures. The data shows that hurricanes/tropical storms and summer storms cause 80% of all major outages. It is easy to conclude that snow and ice accumulation are the major cause of system outages during the winter. From these observations, it would appear obvious to reason that underground facilities would be less prone to these types of major outage events. However, many underground facilities are also affected by these major storms, because, except in a few cases, most existing underground facilities are supplied from overhead sections of the grid. So any event causing an overhead outage will also cause outages on sections of underground facilities.

In Chapter 3.0, we will investigate reliability of both overhead and underground electrical facilities to determine if customers served by either experience any difference in service.

Chapter 3: The Reliability of Overhead and Underground Electrical Systems

For this report, the Edison Electric Institute captured and presented actual utility reliability data. An extensive survey was disseminated to EEI membership to gather information on reliability, construction costs, undergrounding policy information, and utility experiences with underground systems. A copy of the survey is included in Appendix A.

Reliability Data

Gathering and measuring reliability performance data is a daunting task that utilities perform on a daily basis. There are many moving components associated with each outage event that a utility must capture to compile reliability statistics. A utility must know when an outage event starts, determine how many customers are impacted, identify the cause of the outage, and capture the time when each customer is restored. This may seem simple, but consider the complexity of managing the data collection for a major outage event with hundreds of thousands of customers without service and up to 10,000 lineworkers repairing and restoring the electrical system. Utilities have developed complex data gathering systems to assist in collecting and managing the information on outages that allows the utility to better understand the causes of outages and to identify more effective ways to respond and restore the electrical infrastructure.

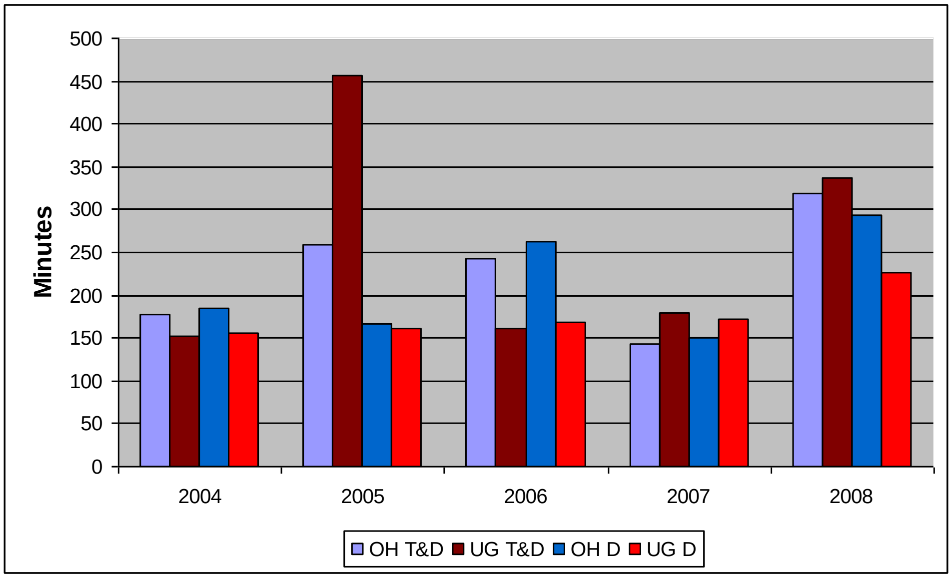
In comparing reliability data of overhead and underground infrastructure, it is worth noting that the overhead and underground elements of a utility electrical system are not always independent of each other. A large portion of underground facilities are served from an overhead feeder. Thus it is difficult to completely isolate the impact of an overhead outage from the underground system or vice versa.

There are many different reliability indices that can be used for comparison. For this report, EEI chose to gather data for three of the most used indices: CAIDI, SAIDI, and SAIFI. The information presented in the following figures represents the average of the data provided from the participating utilities for these indices.

Customer Average Interruption Duration Index (CAIDI)

CAIDI is defined as the average length of an interruption experienced by an interrupted customer, measured in “minutes.” In this index, a customer can be counted as many times as they experience an outage. Figure 3.1 presents the average CAIDI value for years 2004 to 2008, for transmission and distribution combined and distribution alone. The data shows that the underground distribution system has a slight advantage over the overhead distribution system in four of the five years from a national average perspective. Combining transmission data with distribution data demonstrates that the combined overhead transmission and distribution systems out-performed the underground systems in three of the five years.

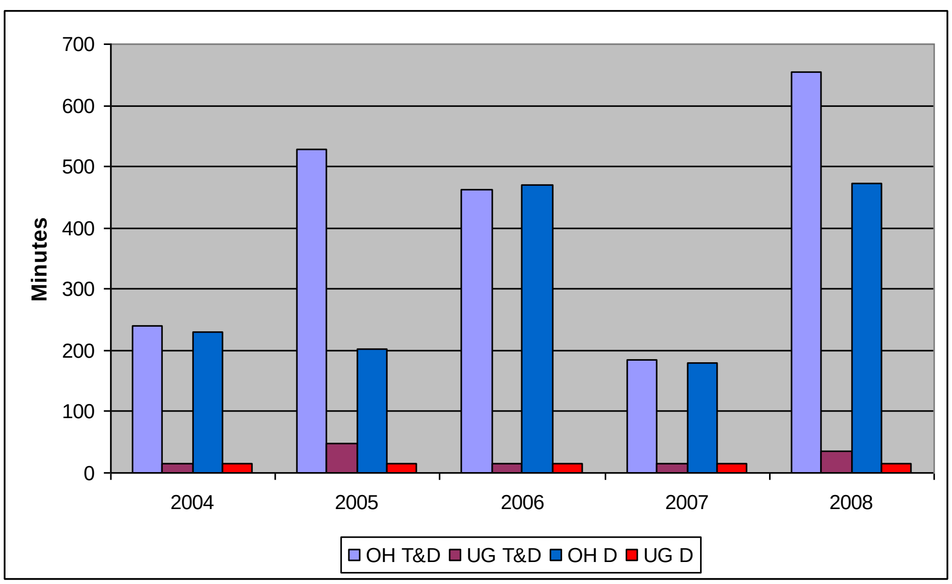
Figure 3.1 Customer Average Interruption Duration Index



System Average Interruption Duration Index (SAIDI)

SAIDI is defined as the average length of an interruption experienced by the average customer, measured in "minutes." In this index each customer is counted only once and all customers are included in the calculation event even if they don't experience an outage. Figure 3.2 present the average SAIDI value for years 2004 to 2008, for transmission and distribution combined and distribution alone. This data set demonstrated that the average customer experiences significantly fewer minutes of outage from underground system outage events.

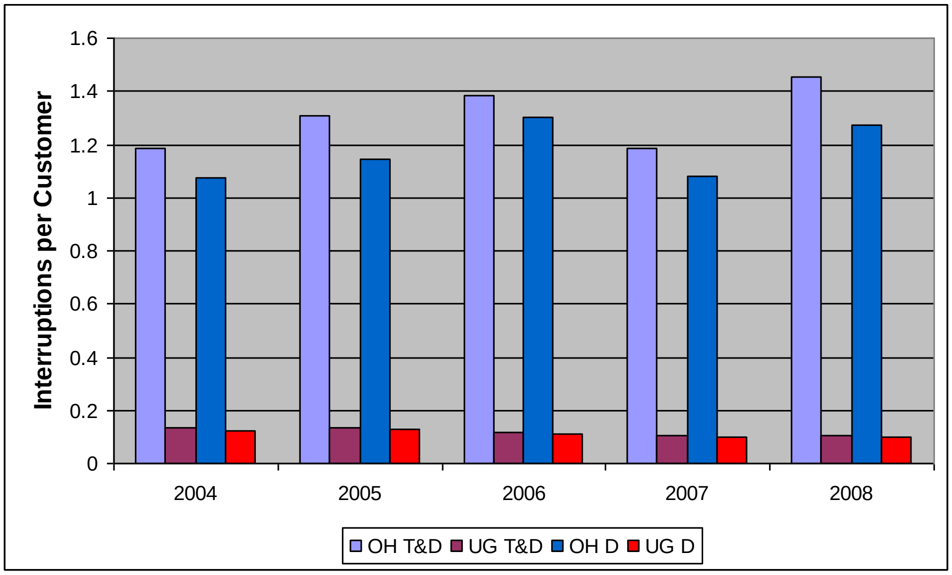
Figure 3.2 System Average Interruption Duration Index



System Average Interruption Frequency Index (SAIFI)

SAIFI is defined as the number of sustained interruptions the average customer experiences, measured in "interruptions per customer." Figure 3.2 presents the average SAIFI value for years 2004 to 2008, for transmission and distribution combined and distribution alone. In this data set, the underground electrical system is shown to contribute significantly fewer interruptions to the average customer outage experience.

Figure 3.3 System Average Interruption Frequency Index

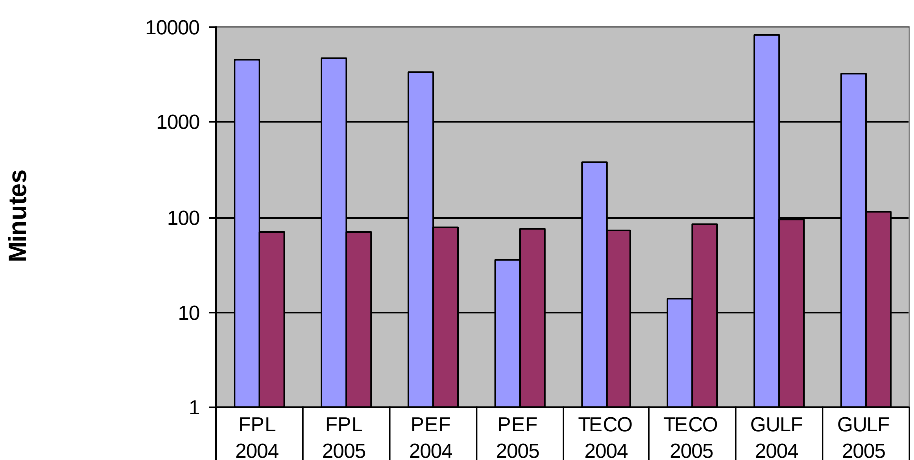


From the given data, it is apparent that the underground electrical system contributes a smaller percentage of the overall outage time to system wide reliability metrics. But because parts of the underground systems are supplied by overhead systems, it is not clear if underground customers consistently experience a higher level of system reliability from a national average perspective.

Impact of Major Storms on Reliability Data

Based on information and data presented in Section 2, it appears that major storms are a catalyst for undergrounding the electrical system. One question that provokes additional investigation is what type of impact major storms have on reliability data. The data presented in Figure 3.4 Storm Effects and Non-Storm Distribution Reliability for Florida Utilities[2] shows just how significant an impact major events have on system reliability. Hurricanes striking Florida during 2004 and 2005 were devastating to the state utilities' electrical infrastructure. For these outage events, the entire electrical system was affected; the underground electrical system was not spared from the effects of any of these storms.

Figure 3.4 Storm Effects and Non-Storm Distribution Reliability for Florida Utilities



	FPL 2004	FPL 2005	PEF 2004	PEF 2005	TECO 2004	TECO 2005	GULF 2004	GULF 2005
Storm	4474	4632	3343	36	387	14	8393	3240
Without Storms	70	70	77	75	73	84	93	115

[2] *Review of Florida's Investor-Owned Electric Utilities' Service Reliability In 2005*, by Florida Public Service Commission - Division of Economic Regulation, Division of Regulatory Compliance and Consumer Assistance, Division of Competitive Markets and Enforcement, December 20, 2006

Chapter 4: Utility Infrastructure

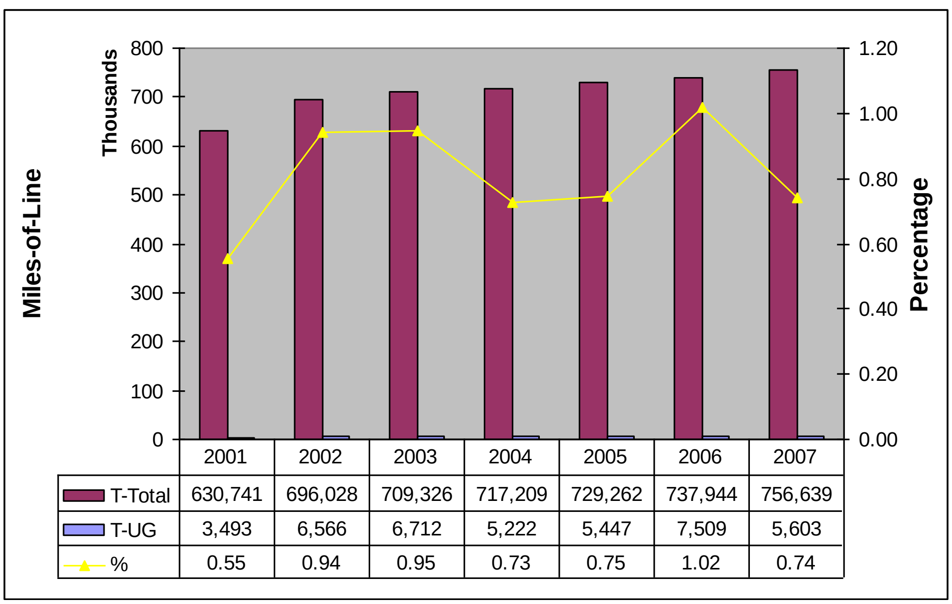
As the industry seeks to address the desire of customers to place more of its electrical infrastructure underground, there have been many studies exploring the possibility of requiring the undergrounding of overhead electrical facilities. The following figures will present data regarding industry support of undergrounding electrical facilities. Two measures are employed: 1) the increase in the miles of underground cable versus overhead line and 2) the amount spent to build underground versus overhead infrastructure.

Miles-of-Line

Acquiring data on the miles-of-line for both overhead and underground transmission and distribution proved to be more difficult than anticipated. EEI worked with Platts' UDI Products Group and compiled Federal Energy Regulatory Commission's (FERC) Form 1 Data to develop the data provided in the following two figures. Because some utilities do not report data each year, totals vary somewhat from year to year (there are more than 3,000 utilities in the United States, including investor-owned, municipal, cooperative, and government owned). The data provides an indication of the magnitude of underground transmission and distribution facilities currently in service.

<u>Figure 4.1 Miles of Transmission Line</u> – This chart presents the annual total miles-of-line in the United States and the amount of underground miles-of-line for the years 2001 to 2007. Because of the discrepancy in data reporting from year to year, the most accurate conclusion that can be drawn from this data is that about 1% of the total miles of transmission line are currently underground. From this data, it is difficult to estimate how much new underground transmission construction has taken place annually.

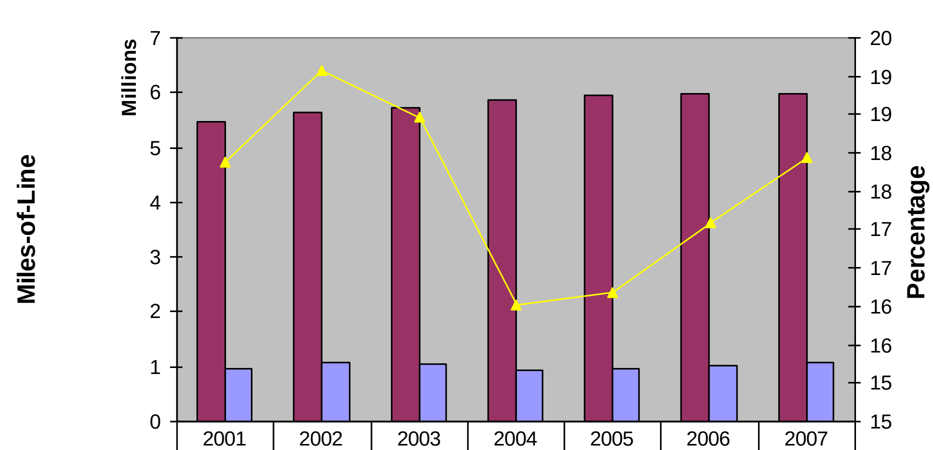
Figure 4.1 Miles of Transmission Line



	2001	2002	2003	2004	2005	2006	2007
T-Total	630,741	696,028	709,326	717,209	729,262	737,944	756,639
T-UG	3,493	6,566	6,712	5,222	5,447	7,509	5,603
%	0.55	0.94	0.95	0.73	0.75	1.02	0.74

<u>Figure 4.2 Miles of Distribution</u> – This data also experiences the same reporting problems that are associated with the transmission miles-of-line data. The distribution data seems to indicate growth in the number of miles of underground distribution line, with underground cables comprising about 18% of the total in service miles-of-line.

Figure 4.2 Miles of Distribution Line



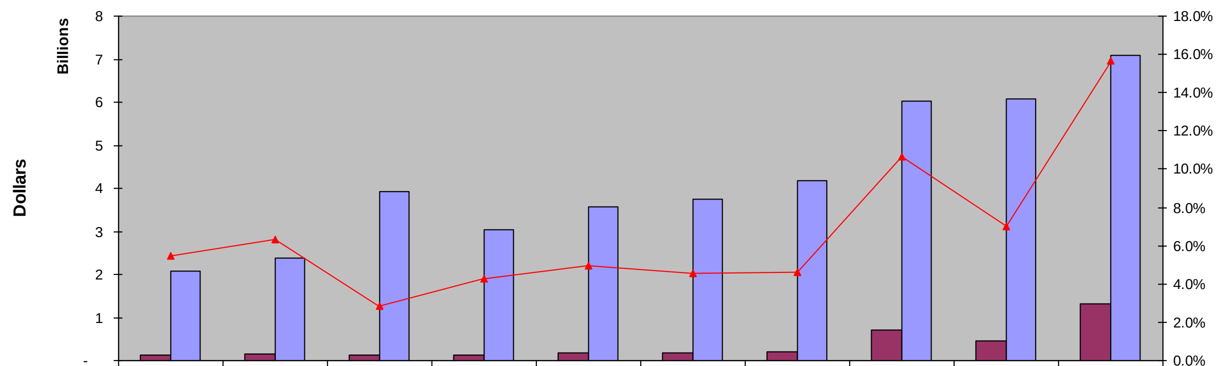
	2001	2002	2003	2004	2005	2006	2007
D-Total	5,468,920	5,627,500	5,735,262	5,878,137	5,937,981	5,975,591	5,972,610
D-UG	977,586	1,073,092	1,059,515	941,883	961,144	1,021,898	1,071,017
%	18	19	18	16	16	17	18

Annual Industry Plant Expenditures

To develop an appreciation of the extent of industry expenditures committed toward expanding underground infrastructure, EEI compiled data on overhead and underground plant expenditures with information gathered from the FERC Form 1 data for the years 1999 to 2008. The data extracted for each year is the total plant expenditures for underground and overhead for both transmission and distribution.

<u>Figure 4.3 Total Annual Transmission Plant Expenditures</u> – This chart shows the trend of increased spending for both overhead and underground transmission over the last 10 years. Industry spending on underground transmission has increased from approximately 4-5% to 7-15% annually of total transmission investment.

Figure 4.3 Total Annual Transmission Plant Expenditures

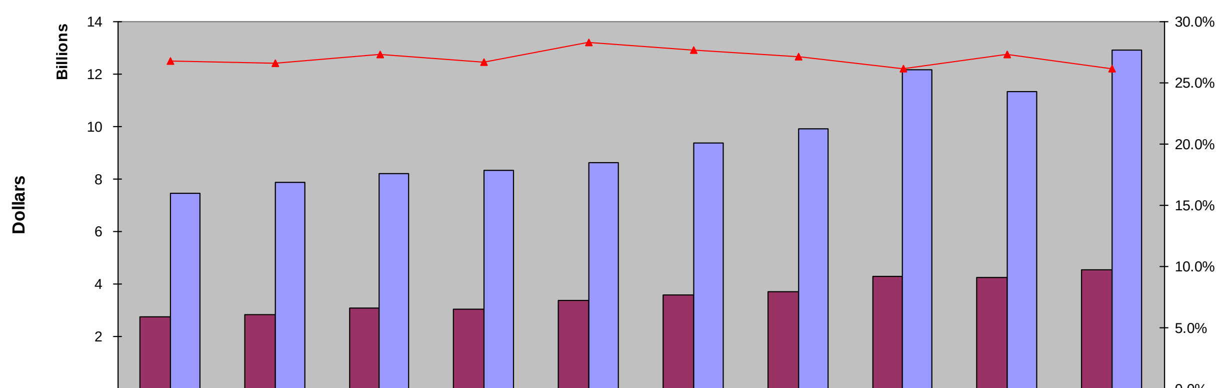


	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
UG	120,843,595	159,463,369	114,088,614	134,621,559	186,834,106	179,616,661	201,776,090	715,963,152	459,780,051	1,317,465,568
OH	2,082,879,464	2,373,498,473	3,928,079,879	3,027,099,072	3,566,079,953	3,753,955,479	4,178,873,543	6,015,092,045	6,077,096,562	7,083,045,778
% UG	5.5%	6.3%	2.8%	4.3%	5.0%	4.6%	4.6%	10.6%	7.0%	15.7%

UG OH % UG

<u>Figure 4.4 Total Annual Distribution Plant Expenditures</u> – This chart also shows the trend of increased spending for both overhead and underground distribution during the past 10 years. Industry spending on underground distribution has nearly doubled from $2.7 billion in 1999 to $4.5 billion in 2008. This has resulted in a consistent level of investment in underground distribution facilities of between 26-27% of all dollars invested in distribution facilities annually.

Figure 4.4 Total Annual Distribution Plant Expenditures



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
UG	2,730,619,792	2,851,792,350	3,083,200,483	3,030,348,970	3,395,201,700	3,583,589,963	3,692,967,631	4,300,663,150	4,265,929,876	4,560,356,356
OH	7,462,523,562	7,855,547,816	8,211,240,878	8,316,593,120	8,604,965,424	9,383,937,604	9,927,920,335	12,162,800,750	11,333,519,122	12,896,373,019
% UG	26.8%	26.6%	27.3%	26.7%	28.3%	27.6%	27.1%	26.1%	27.3%	26.1%

UG OH % UG

Although the miles-of-line data does not show a clear increase in the amount of new construction of underground facilities, the FERC data on new plant expenditures does demonstrate the commitment of the electric industry to invest and construct new underground infrastructure.

Chapter 5: Benefits and Challenges to Undergrounding

Benefits of Undergrounding

To begin to understand the benefits derived from placing electrical infrastructure underground, it is useful to understand the perspective and experiences of how utilities perceive the value and the issues associated with underground facilities. In the EEI member survey, utilities were asked "What benefits does your utility derive from your underground system?" Their answers clearly reflected a perceived value, with examples including improved reliability, improved system performance, more effective routing of multiple feeders in confined areas, and the enhancement of the visual aesthetics of roadways and streets in residential and business communities. The following is a summary of utilities' responses:

Reliability

- Reduced outages due to vegetation, which is always the number 1 or 2 cause of outages
- The elimination of outages caused by trees, wind, and animals
- Shielded from tree-related damage, the most frequent cause of overhead system outages
- Fewer power outages and improved reliability because circuits are protected
- In very dense urban areas, overhead construction becomes impractical, so the utility benefits by having the option of installing underground network systems in these areas where overhead can't realistically be installed
- Underground construction does tend to sustain less damage during storms than overhead systems, although it should be stressed that underground is not completely immune to storm damage (e.g., flooding and damage to cables from uprooted trees)
- Better reliability and lower route congestion near urban substations

Aesthetics

- An increase in customer and public goodwill due to aesthetics
- Aesthetically pleasing to customers and the public
- One of the major benefits is to help create positive community relations by mitigating visual impact

Other

- Increased customer acceptance for new projects
- Less resistance from towns for project approvals
- Ability to maintain facilities at ground level, rather than from poles and bucket trucks
- Significant reduction in R/W maintenance costs and vehicular caused outages
- Increased customer satisfaction

Challenges of Undergrounding

In presenting and reviewing the challenges of undergrounding electrical systems, it is worth reiterating that underground utility systems take longer and cost more both to install and to repair. Utilities do seek to provide the best service at the lowest cost; however, from a cost perspective, placing infrastructure underground seems to go counter to this basic objective.

There is an additional downside, as indicated by the following quotation from one of the respondents: "In our area, undergrounding can help protect against wind events, but can actually make us more vulnerable to outages from flooding in some areas. The heavy rains that the Houston area experienced during Tropical Storm Allison in 2001 would have inflicted more damage on an underground electrical distribution system than on an aerial system."[3]

The EEI Survey identified many other disadvantages of having power lines and other equipment underground. In addition to higher cost for underground facilities, disadvantages include longer repair times, making system changes or upgrades difficult, and damage from dig-ins.

The following list is a summary of the survey responses to the question "What issues and/or problems does your utility address because of your underground system?":

Costs

- Underground systems are normally more expensive to install than overhead systems.
- Higher facility replacement costs
- Increased project costs associated with UG systems
- Increased material costs and longer installation timeframes vs. overhead
- Design redundancy/significantly higher capital costs for installation
- Higher O&M cost offsets corresponding reduction in R/W maintenance costs

Operation and Maintenance

- Repair times for UG construction are substantially higher than for OH construction, driving up maintenance costs and duration-based reliability indices.
- Restoration in the direct buried systems can be more costly and time consuming compared to the overhead system.
- More complex operational needs, as visual inspection is impossible, making it more difficult and costly to maintain and repair.
- Damage to underground facilities typically takes longer to locate and longer to repair than similar damage to overhead facilities.
- Underground facilities are generally less flexible than overhead facilities (e.g., more difficult to upgrade capacity, add unplanned transformers, etc.).

[3] *Electric Service Reliability in the Houston Region*, Mayor's Task Force Report, April 21, 2009, Houston, Texas

- Underground facilities are subject to damage from dig-ins.
- Installation of underground services requires much more coordination between the utility and customer than similar overhead service installations.
- Although UG construction eliminates some outage causes, UG systems are still vulnerable to lightning and equipment failure.
- Difficulty locating space for padmounted gear.
- Increased stray voltage concerns.
- Some of our challenges include our underground systems being damaged by others.
- It is more costly to install and maintain, outages are typically longer (unless more costly automatic switching infrastructure is implemented) than in the overhead system. The skill sets to install and maintain these systems are more complex and less available.
- More complex than overhead, leads to longer troubleshooting/restoration times.
- Specialized training/equipment for manhole/vault access.
- Surface mounted equipment inspections critical to protect public.

Failure Issues

- System longevity of UG construction has so far proven to be on the order of 30 years, as opposed to 50 years for OH construction.
- The biggest problem that we address is aging cable and duct. Older cables are more likely to fail and older tile or fiber duct systems are more likely to collapse when failed cable is pulled.
- Implemented a formal cable replacement program in 2008 as a result of increasing failures of early vintages of direct buried cable.
- Another issue is the time needed to restore any underground cable failures.
- Damage from dig-ins.
- Slower outage restoration and fault isolation, because it is more difficult to find the problem on the UG system; therefore, it takes longer to restore.
- Customer perception that undergrounding their service or neighborhood should dramatically improve their reliability, not taking into account exposure of overhead portions of the system upstream.

Conflict between Benefits and Challenges

One apparent conflict between the benefits and challenges associated with underground facilities is "improved reliability" and "longer restoration times." On the surface it would appear that these two factors are mutually exclusive, i.e., they cannot both be true for the same underground system. To understand how both of these statements are true, we must take into account some of the differences in typical overhead and underground system construction and operations. Consider the example scenario of how a small subdivision would be served with an overhead or underground electrical system.

Typical service for a subdivision served by an overhead configuration would consist of the construction of a signal phase line tapped off the main feeder circuit, with a fused cutout as a disconnect point. This tap line would be a radial line that did not connect back to the main circuit, but came to a dead end in the subdivision. Any type of fault on this line would cause the fuse to blow and would require utility personnel to restore service to the subdivision. In this configuration, the entire subdivision would be out of service until the problem was fixed.

If the subdivision was served with a typical underground configuration, the construction technique would require underground line tapping off the main feeder which would be looped through the subdivision and connected back to the main feeder at another tap point. This underground loop would have two feeds with an open point in the middle line, most likely at a transformer. In the case of a fault in this system, only one of the two tap fuses would blow, limiting the outage to only part of the subdivision. When utility personnel responded to this outage, they would seek to identify the problem area on the circuit, then isolate this problem area, and reconnect as much of the loop as possible with the problem area de-energized.

The underground system has built-in flexibility that allows the utility to restore most, if not all, of the customers' service before repairing the problem that caused the outage. The overhead system requires the problem to be repaired before service is restored; for an overhead system, this can be a relatively quick process because the problem can be visually identified and accessed easily. For the underground problem, a line fault may be easily identified between two transformer locations, but pinpointing the exact location can be time consuming. The utility will have to determine if they can repair the problem or whether equipment or cable must be replaced. All of this takes significantly more time than an overhead repair.

Chapter 6: Undergrounding Costs

The economics of undergrounding utility infrastructure has always been the overarching challenge for the utility and customers who wanted lines put underground. If the cost of undergrounding were nearly the same as overhead construction, the decision would be easy. But that is not the case.

The EEI survey collected data on the estimated cost per mile for new overhead construction, new underground construction, and the cost to convert from overhead to underground. The survey also collected data on the percentage breakdown of these costs between materials and labor to see if underground construction is a more labor intensive (and even more costly) process. This report has also compared its findings with economic data from other sources.

Collecting and comparing cost data from across the country presents many challenges. There are many different variables to contend with including customer density (urban, suburban, and rural), soil conditions (sandy to rocky), labor costs, construction techniques, vegetation, and voltage levels. This report has attempted to handle these variables in two ways, as follows.

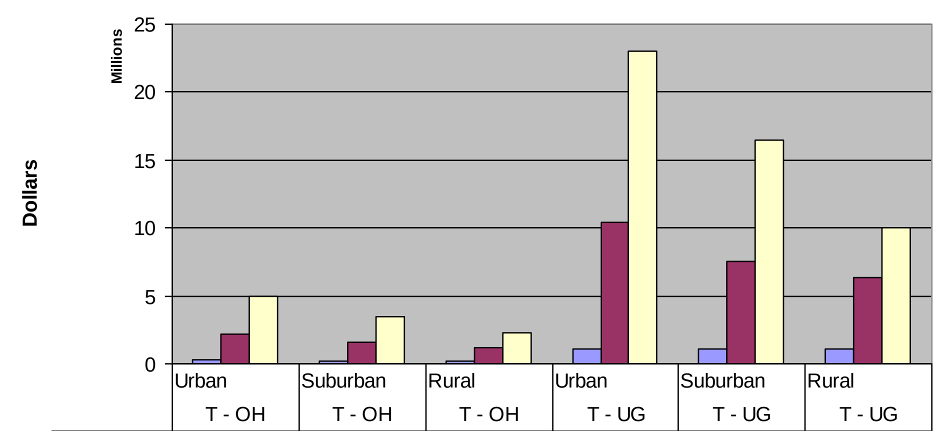
> First, data has been collected based on customer density, defined as:
>
> Urban – 150+ customers per square mile
> Suburban – 51 to 149 customers per square mile
> Rural – 50 or fewer customers per square mile
>
> Second, the report seeks to identify the range of costs for each category discussed, identifying the highest, lowest, and average estimated costs in each category.

The issue at hand is that there is no precise cost per mile to build utility facilities of any type for any utility. Every construction project is unique because load, number of customers served, and construction parameters are all different. The cost data in this report is not meant to be the absolute range into which utility construction costs must fall, but this data is intended to give the reader a range of cost data that utilities have estimated on various projects.

Transmission Costs

Figure 6.1 Cost Per Mile: New Construction Transmission – This chart presents a range of costs for new construction of transmission. Overhead costs range from $150,000 per mile (for rural construction) to $5,000,000 per mile (for urban construction). Likewise, underground costs range from $1,100,000 per mile (for rural construction) to $23,000,000 per mile (for urban construction). When drawing conclusions from the data provided for transmission construction, remember that the construction requirements associated with different voltage levels contribute greatly to the cost variations. Higher voltage transmission lines require larger poles/towers and greater insulation levels in order to transmit electricity. The cost for new underground construction may range from five to ten times the cost for comparable overhead construction. For example, in the survey, the utility that provided the minimum cost of $325,000 per mile for overhead urban transmission construction also provided a cost of $3,000,000 per mile for similar underground construction.

Figure 6.1 Cost Per Mile: New Construction Transmission



	Urban T - OH	Suburban T - OH	Rural T - OH	Urban T - UG	Suburban T - UG	Rural T - UG
Min Value	325,000	200,000	150,000	1,100,000	1,100,000	1,100,000
Average	2,190,500	1,613,333	1,216,364	10,464,286	7,528,819	6,350,000
Max Value	5,000,000	3,500,000	2,280,000	23,000,000	16,500,000	10,000,000

A simple visual example of the complexity of the underground cable compared to the overhead wire is the conductor used to transmit electricity. Figure 6.2, Utility Cables, shows an example of an overhead conductor and an underground cable. By simple inspection it is easy to see how the construction of the underground cable is much more complex than the overhead. This complexity results in a much more expensive component.

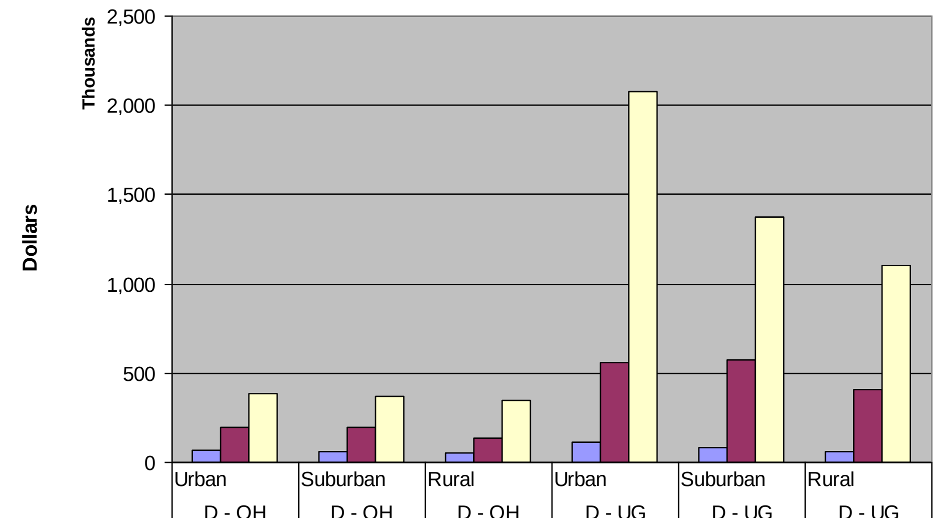
Figure 6.2 Utility Cables

Overhead Conductor	Underground Cable
	

Distribution Costs

<u>Figure 6.3 Cost Per Mile: New Construction Distribution</u> – This chart presents a range of costs for new construction of distribution. Overhead costs range from $53,000 per mile (for rural construction) to $386,000 per mile (for urban construction). Likewise, underground costs range from $63,000 per mile (for rural construction) to $2,074,000 per mile (for urban construction). For overhead distribution, voltage level does not contribute as greatly to the variation in costs as it does in transmission lines. The variation in costs from rural to urban is related to the need for a greater number of poles or manholes, transformers, and service drops per mile. The author strongly cautions readers not to assume that the low end costs provided by some utilities can be replicated by every utility. The distribution data collected from utilities shows that underground construction can be five to ten times more expensive than overhead construction.

Figure 6.3 Cost Per Mile: New Construction Distribution



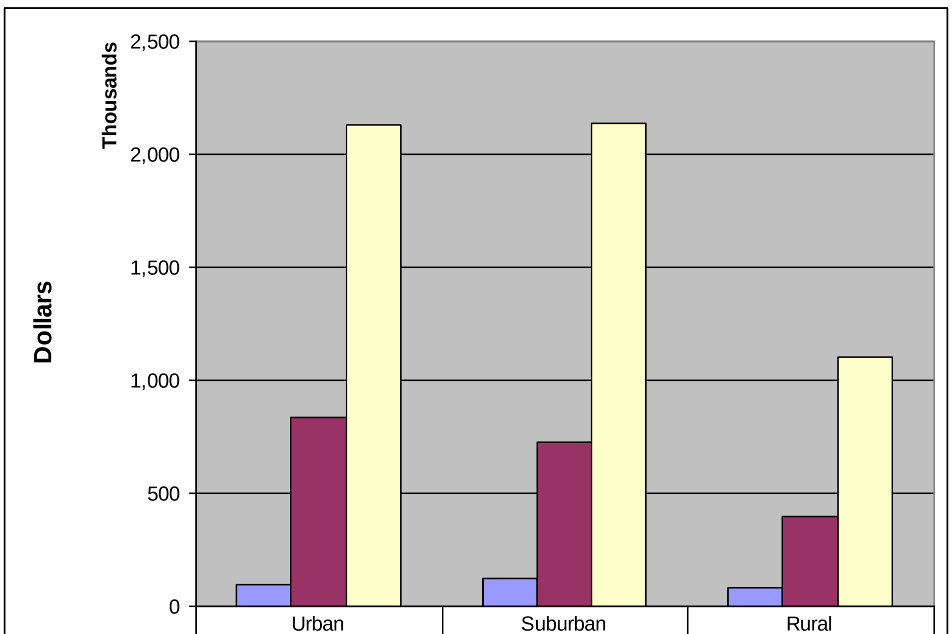
	Urban D - OH	Suburban D - OH	Rural D - OH	Urban D - UG	Suburban D - UG	Rural D - UG
Min Value	67,892	63,000	53,000	117,000	80,000	63,000
Average	196,628	193,850	135,307	559,293	571,400	408,532
Max Value	386,000	368,000	351,000	2,074,000	1,375,000	1,100,000

Conversion Costs

The EEI survey attempted to collect cost per mile conversion costs for transmission. However, because few utilities providing data had experience converting overhead transmission to underground, the amount of data was limited. Therefore, in the opinion of the author, there is not enough data to provide a full range of potential conversion costs for transmission in this report.

Figure 6.4 Cost Per Mile: Converting Overhead to Underground Distribution – This chart presents a range of costs for converting distribution overhead electrical facilities to underground facilities. The conversion costs ranged from $80,000 per mile, for rural construction, to $2,130,000 per mile, for urban construction. The conversion costs may not appear to differ much from the cost of new underground distribution construction. The salvage value of the overhead system that is removed during a conversion can greatly help to offset some of the conversion costs.

Figure 6.4 Cost Per Mile: Converting Overhead to Underground Distribution



	Urban	Suburban	Rural
Min Value	93,202	120,000	80,000
Average	832,383	723,692	395,874
Max Value	2,130,000	2,138,400	1,100,000

Figure 6.5 State Reports Conversion Cost Comparison – This chart provides a comparison of the conversion cost data collected by the EEI survey and data collected by various state studies. The states conducting each study and the year the study was published are listed in the table; more information about each study can be found in Chapter 8. All but one value from the other studies falls within minimum and maximum values of the EEI data.

Figure 6.5 State Reports Conversion Cost Comparison

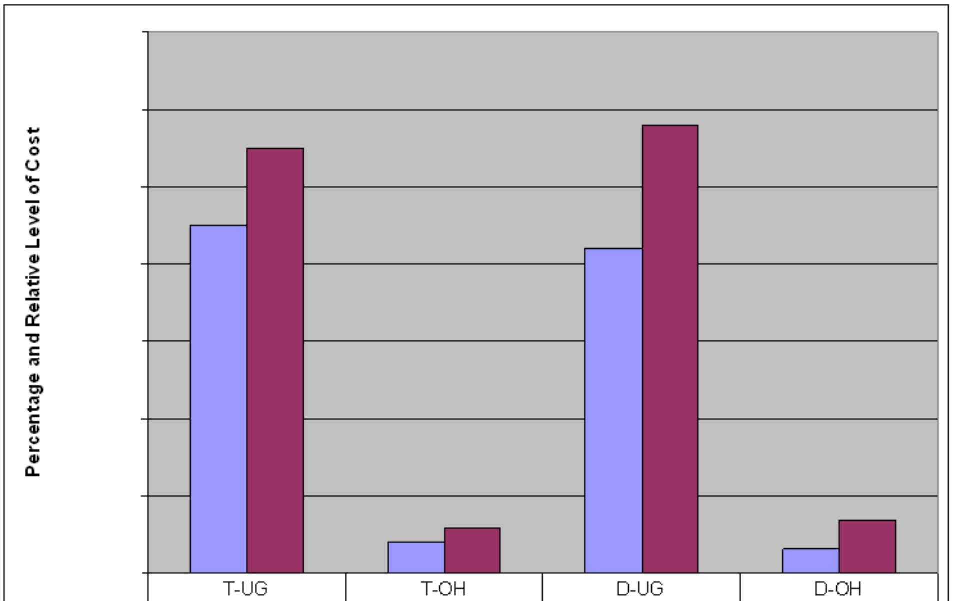
State Reports Conversion Cost Comparison			
State Year of Study	Estimate / Actual Cost	Project Information	Cost per Mile
EEI, 2009	Estimate	Minimum Cost	$80,000
North Carolina, 2003	Estimate	Minimum Cost	$151,000
Maryland, 1999	Estimate	Minimum Cost	$350,000
Florida, 2007	Actual	Allison Island	$414,802
Florida, 2007	Actual	County Road 30A	$883,470
Florida, 2007	Actual	Sand Key	$917,532
Virginia, 2005	Estimate	Average Cost	$1,195,000
Oklahoma, 2008	Estimate	Average Cost	$1,540,000
Florida, 2007	Actual	Pensacola Beach	$1,686,275
Maryland, 1999	Estimate	Maximum Cost	$2,000,000
EEI, 2009	Estimate	Maximum Cost	$2,130,000
North Carolina, 2003	Estimate	Maximum Cost	$3,000,000

Labor and Material Costs

EEI also investigated whether there was a significant difference in the proportion of labor costs for underground construction as compared to overhead construction. The data in the survey showed that labor costs for underground construction actually consumed a slightly smaller part of the total project cost, as compared to overhead construction. However, underground projects cost three to five times more than overhead projects; therefore, labor costs for underground construction are much greater than overhead labor costs.

Figure 6.6 Material and Labor Percentages – This chart demonstrates how costs for new construction are broken down between material and labor percentages. These values are average values from the data collected by the EEI survey. Some may assume that underground construction labor costs are the cause for the higher underground cost. The relative breakdown between cost and material differs only around five to ten percent between overhead and underground construction. Higher undergrounding costs are equally driven by the material component of the cost. To help represent the relatively higher overall cost for underground construction, the chart has been proportioned to demonstrate the higher costs of undergrounding.

Figure 6.6 Material and Labor Percentages



	T-UG	T-OH	D-UG	D-OH
Materal	45	40	42	32
Labor	55	60	58	68

Chapter 7: State Policies and Utility Approaches to Undergrounding

Utility Policies for New Underground Construction

For nearly all new residential and commercial developments it has become the electric industry's standard to provide underground electrical service. Also, for new stand-alone customers, utilities will typically provide underground services as an option. Regardless of whether the new customer is part of a development, a stand-alone customer, or in a high density urban setting there is typically a cost associated with new underground electrical service.

Utilities recover undergrounding costs in basically two ways: either by incorporating the cost into the basic utility electric rate or by charging a connection fee for underground service. There are some variations for these undergrounding fees:

- Rate base approach – In high density urban settings where standard utility construction is underground (large cities like New York) the cost for undergrounding is part of the basic electric rate that the customer pays each month. In these locations the electric rates are higher to compensate for the high cost of the underground electrical network.
- Cost difference approach – The typical approach that utilities use to calculate customer charges for providing underground service is to determine the cost difference between typical overhead construction and underground construction. Customers, or in many cases the developer, have to pay these fees before utility construction will begin.
- First few feet free – A common variation of the cost difference approach that a few utilities offer is to provide the first few hundred feet of underground service at no additional charge to the customer. In cases where the distance from existing utilities facilities exceeds the free distance, the customer would be charged the cost difference between typical overhead construction and underground construction for the additional distance.

Appendix B provides an overview of different company policies for new underground construction for 14 utilities that provided feedback to the EEI survey.

Utility Policies for Converting Existing Overhead Facilities to Underground

All utilities have polices and procedures for the conversion of overhead facilities to underground facilities. In nearly all cases there are associated fees for the conversion. For most utilities, the conversion charges that customers are required to pay is equal to the cost of installing the underground electrical system plus the cost of removing the overhead electrical system, minus the salvage value of the removed overhead facilities. In nearly all conversion situations, customers are responsible for the work and costs for converting their electrical service facility (meter base and service connection point) from overhead to underground.

Some utilities have special policies for conversion requests from municipalities. In high density urban areas where electrical load is high, utilities and municipalities may work together to offset some of the costs of the conversion (with the city providing land and space for underground utility facilities). Cities may also provide trenching and conduits for cables and vaults for transformers to help defray some of the undergrounding costs.

Some state utility commissions have set rules in place (e.g., California Rule 20) that dictate a process in which municipalities and utilities work together to identify a limited number of facilities that can be converted to underground each year. Once the conversion is completed the associated cost is added to the utilities' rate base.

Other utilities are running pilot projects. For instance, Duke Energy Carolinas will work with municipalities to place qualifying areas underground. The expenses for these conversion projects are funded by a Duke fund with municipality matching funds for up to 0.5% of Duke's taxable gross receipts from furnishing electricity within the municipality.

Appendix C provides an overview of different company policies for overhead to underground conversions for the 13 utilities that provided feedback to the EEI survey.

Additional Policies

In the EEI Survey, EEI sought to determine if there were other policies that played a role in encouraging the conversion of overhead facilities to underground. EEI's survey asked the following additional questions:

- Are there special rate areas associated with these types of conversions?
- Does your PUC have additional policies that you must comply with associated with converting existing overhead facilities to underground?

The overall responses to these questions were negative. No utility indicated that they had a special rate for overhead to underground conversion customers or that their PUCs had additional compliance policies.

Chapter 8: State Undergrounding Studies

Over the last 10 years, at least eight state utility commissions have studied the possibility of mandating utilities to place all or part of their electrical facilities underground. Each of these studies has been the result of a catastrophe weather event that left hundreds of thousands of customers without electrical service for many days. The general consensus from all of these studies has acknowledged the value of the specific undergrounding; however, it is agreed that it is too expensive to require that all electric facilities to be placed underground. Some of the key findings from these studies are:

Florida – There is insufficient data to show that this high cost is 100% justifiable by quantifiable benefits such as reduced O&M cost savings and reduced hurricane damage.

Houston, Texas – The cost of undergrounding the existing distribution infrastructure is prohibitive. It would cost an estimated $35 billion to bury the cables of the entire regional distribution system.

North Carolina – Replacing the existing overhead distribution lines of the utilities with underground lines would be prohibitively expensive. Such an undertaking would cost approximately $41 billion, nearly six times the net book value of the Utilities' current distribution assets, and would require approximately 25 years to complete. The ultimate impact on an average residential customer's bill would be an increase of more than 125%.

Oklahoma – Information gathered … clearly indicated that requiring electric utilities to underground all of their facilities is generally not a feasible solution. The cost to underground … would likely run into the billions of dollars, and the potential impact on customers would … approach thousands of dollars per customer.

Virginia – The cost associated with undergrounding was estimated to be over $80 billion. The resultant annualized revenue requirement on a per customer basis would be approximately $3,000. The potential benefits … resulting from the elimination of tree trimming maintenance, vehicle accidents, post storm restoration, and lost sales during outages, do not appear to be sufficient to offset the initial construction costs.

Complete undergrounding of all electrical facilities is not the solution to the outage problems caused by storms. These studies have helped to identify ways of improving service reliability as state commissions are now working with their utilities to identify ways to harden the electric utility infrastructure, with the hope of reducing the ensuing outages caused by storms.

The executive summaries of the 11 state studies identified by this author are provided in Appendix D. Reports are listed with the most recent chronological order first.

Chapter 9: Conclusion

For customers, improved aesthetics and the hope that underground electrical facilities will provide greatly enhanced electric reliability will continue to be the driver for their desire for undergrounding of utility facilities. In this edition of *Out of Sight, Out of Mind*, EEI and the author have investigated issues which have not been discussed in other studies to examine whether any light could be shed on the undergrounding topic. By investigating the reliability impact of major weather events, comparing the reliability of overhead and underground systems, and looking at the number of annual construction of underground facilities by utilities, this report has attempted to expand the available knowledge on the factors associated with the desire for undergrounding.

Out of Sight, Out of Mind Revisited has shown the significant impact that major weather events have on reliability metrics. The resulting Florida hurricane data has demonstrated that major events can increase outage minutes by a factor of several hundred. The data collected has indicated that underground facilities do tend to have a slightly better reliability performance than overhead, but underground systems are not without their share of inherent outage problems. Utility experience has shown that during a major outage event, the entire utility system is affected, not just the overhead system.

The available data has demonstrated that utilities are investing significantly in the construction of new underground facilities, spending 7% to15% of transmission dollars annually on underground construction and about 26% of distribution dollars annually on underground construction.

This study has shown that utilities see value in and are open to undergrounding their overhead facilities. However, the challenge for utilities and customers is the high cost of building new or converting existing facilities to an underground electrical system. The data has shown that underground vs. overhead costs can be five to ten times greater for transmission distribution construction.

This paper has sought to investigate areas not previously discussed, thereby providing a larger picture of the resources that utilities are currently investing in undergrounding and the resulting reliability derived from these expenditures. Undergrounding is not an issue that will be completely resolved, but will continue to be an active process where utilities and customers work together to balance the desire for undergrounding with the cost, reliability, and aesthetic value derived from it.

Appendix A: 2009 EEI Out of Sight, Out of Mind Survey

2009 EEI Out of Sight, Out of Mind Survey

Name	
Holding Company Name	
Operating Company Name	
State of Reliability Reporting	
Email Address	
Phone Number	

Note: For this study we will allow the user to define transmission, distribution, primary, secondary, and services.

	Number of Miles of Line										
	Overhead						Underground				
	2004	2005	2006	2007	2008		2004	2005	2006	2007	2008
Transmission											
Primary											
Secondary / Services											

Notes: 1. Include all non-planned outages in data (all storms)
2. An outage is any event over 5 minutes in length

	CAIDI Reliability Data (minutes)										
	Overhead						Underground				
	2004	2005	2006	2007	2008		2004	2005	2006	2007	2008
Transmission & Distribution											
Distribution only											

	SAIDI Reliability Data (minutes)										
	Overhead						Underground				
	2004	2005	2006	2007	2008		2004	2005	2006	2007	2008
Transmission & Distribution											
Distribution only											

2009 EEI Out of Sight, Out of Mind Survey

SAIFI Reliability Data	Overhead					Underground				
	2004	2005	2006	2007	2008	2004	2005	2006	2007	2008
Transmission & Distribution										
Distribution only										

Total Annual Outage Minutes	Overhead					Underground				
	2004	2005	2006	2007	2008	2004	2005	2006	2007	2008
Outage Minutes										

Cost Per Mile-New Construction	Overhead			Underground		
	Urban	Suburban	Rural	Urban	Suburban	Rural
	(150+ cust/sq. mi.)	(51-149 cust/sq. mi.)	(≤50 cust/sq. mi.)	(150+ cust/sq. mi.)	(51-149 cust/sq. mi.)	(≤50 cust/sq. mi.)
Transmission						
Primary						
Secondary / Services						

Cost Per Mile-New Construction System Average	% Material UG	% Labor UG	% Material OH	% Labor OH
Transmission				
Primary				
Secondary / Services				

Cost Per-Mile Converting Overhead to Underground	Urban	Suburban	Rural
	(150+ cust/sq. mi.)	(51-149 cust/sq. mi.)	(≤50 cust/sq. mi.)
Transmission			
Primary			
Secondary / Services			

2009 EEI Out of Sight, Out of Mind Survey

Additional Questions:

1. What benefits does your utility derive from your underground system?
2. What issues and/or problems does your utility address because of your underground system?
3. What is your company's current policy for new underground construction? Please provide a copy.
4. What is your company's current policy for converting existing overhead facilities to underground? Please provide a copy.
5. Are there special rate areas associated with these types of conversions? Please provide details.
6. Does your PUC have additional policies that you must comply with associated with converting existing overhead facilities to underground? Please provide a copy.
7. Has your PUC or state government published any studies or reports addressing converting existing overhead facilities to underground? Please provide a link or a copy.

Appendix B: Utility Policies for New Underground Construction

Ameren – Illinois

A single-phase overhead or underground Line Extension up to 250 feet, plus any necessary transformer and associated protective devices, may be provided free.
Customers extending from a Line Extension on which the Company is already holding a deposit will still be entitled to a free Line Extension. In addition, the Customer whose deposit is being held is still subject to refunds.

a) For Extensions greater than the free allowance, Customer will have the choice of the following two options:

    i. Refundable Deposit
    The first option is for the Customer to provide a **Refundable** Deposit to pay for the cost of the Line Extension, calculated as the Standard Line Extension Refundable Cost per Foot, multiplied by the footage in excess of 250 feet.

    ii. Discounted Non-Refundable Contribution
    The second option is for the Customer to provide a **Non-Refundable** Contribution to pay for the cost of the Line Extension, calculated as the Standard Line Extension Non-Refundable Cost per Foot, multiplied by the footage in excess of 250 feet. This amount provides a discount from the Standard Line Extension Refundable Cost per Foot by including a credit for an assumed additional Customer every 1,000 feet. Consequently, Customers choosing this option will not receive any refunds as additional Customers locate on the Extension.

b) All Refundable Deposits and Non-Refundable Contributions are to be paid by the Customer or Applicant prior to the start of construction.

c) Additional Options for Underground Line Extensions

The Customer may be allowed to furnish and install a conduit system on his premise or public right-of-way for either primary or secondary voltage cables. If primary/secondary conduit is installed by Customer, the Non-Refundable Contribution for the cable installation will be the Nonrefundable Cable in Conduit Installation Charge for any distance over the 250 foot allowance.

Allegheny Energy – Maryland, Pennsylvania, West Virginia, Virginia

Customer/Developer must provide all trenching conduit and backfill; with the exception of Lot Plans (5 or more lots) in VA (Allegheny Energy provides trenching, conduit and backfill per the VA Tariff Plan C).

Central Hudson – New York

Underground Residential Distribution Systems in Subdivisions:
Any distribution line, service line, and appurtenant facilities necessary to furnish permanent electric service to one or more multiple-occupancy dwellings (including four or more dwelling units) or within a residential

subdivision in which it is planned to build five or more new residential buildings shall be installed underground if:

i. the residential subdivision will require no more than 200 trench feet of facilities per dwelling unit planned; or

ii. a governmental authority having jurisdiction to do so has required undergrounding; or

iii. the applicant requests undergrounding.

Connecticut Light & Power Company – Connecticut

Overhead construction is the standard with the exception of conventional underground construction in downtown city environments. However, nearly all municipalities require new residential and commercial developments to be underground construction. Private developers also have the choice to request underground construction. In all cases, the developer must pay the differential cost between underground construction and standard overhead construction. The regulatory commission does not dictate when extensions should be underground or overhead construction, but they do regulate the policy for determining the customer contribution.

Detroit Edison – Michigan

Existing rules issued by the Michigan Public Service Commission require that distribution systems in a new residential subdivision and commercial distribution and service lines in the vicinity of or on the customer's property and constructed solely to serve a customer or a group of adjacent customers be placed underground. The general policy of the Company is that real estate developers, property owners, or other applicants for underground service shall make a non-refundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.

Duke Energy Carolinas – North Carolina, South Carolina

RESIDENTIAL SERVICE – At the request of an owner, the Company will install, own, and maintain underground facilities for service to single residences, apartments, condominiums, and manufactured homes following these Plan provisions. Any charge to the owner is for the cost difference of the necessary underground facilities requested and is nonrefundable. The signed agreement with the owner for underground service shall specify the payment arrangements.

Permanent Residences – Residences which are to be permanent customer locations on a residential rate schedule of the Company will be served from underground facilities as shown below.

1. New Service Installations Located in New Developments
    - Service to new residences on lots averaging an acre (43,560 sq. ft.), or less – No Charge
    - Service to new residences on lots averaging more than one acre – No charge except for cost difference of new primary facilities exceeding 300 feet per lot.
2. New Service Installations Not Located in New Developments
    - Service to new residences requiring new underground secondary voltage facilities from an above-ground distribution line on, or adjacent to, the lot on which the residence is located. – No Charge

- Service to new residences requiring new underground primary and secondary voltage facilities – No charge except for cost difference of new primary facilities exceeding 300 feet.

3. New Three-Phase Service Installations
   - Three-phase service to new single-residence structures, where this type of service is available. – No charge except for cost primary difference of new primary facilities exceeding 300 feet.
   - Three-phase service to new multi-residence structures, where this type of service is available. – No Charge

NON-RESIDENTIAL SERVICE

At the request of an owner, the Company will install, own and maintain underground facilities to new general service and industrial service installations following these Plan provisions. Any charge to the owner is for the cost difference of the necessary underground facilities requested and is non-refundable. The signed agreement with the owner for underground service shall specify the payment arrangements.

1. New Service Installations Requiring Only Secondary Voltage Facilities – No Charge
2. New Service Installations Requiring Primary Voltage Loop System Facilities – No Charge
3. New Service Installations Requiring Primary Voltage Radial Extension Facilities – No charge except for cost difference of single-phase primary facilities exceeding 300 feet, or three-phase primary facilities exceeding 500 feet. For three-phase primary facilities exceeding 500 feet, additional underground footage will be provided at no charge when installation of underground facilities is less than comparable overhead facilities.
4. New Bulk Feeder and Subfeeders – Cost difference of such primary facilities.

Entergy – Arkansas, Louisiana, Mississippi, Texas

Except for downtown network areas, the default system for new construction is overhead. The company generally requires payment of the installation cost difference between overhead and underground construction before underground will be installed.

Hawaiian Electric – Hawaii

The Company will install its distribution system underground only when the customer, developer, or sub-divider makes a contribution of the estimated difference between the cost of the underground system and an equivalent overhead system, or when for engineering and operating reason the company may install the system underground at its own expense.

NorthWestern Energy – Montana

The Utility will install underground distribution lines in new service areas of five (5) or more consumer units when undergrounding is technically feasible.

Upon application for electric service, the Utility shall make an Electric Line Extension, including primary and secondary service lines to the applicant (except that the applicant shall furnish all necessary rights-of-way) as follows:

A. In the case of an application for residential service, a maximum free extension allowance of $500 plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer and meter.

B. In the case of an application for general service (GS), a maximum free extension allowance of:

1. GS non-demand metered service; $0.04/kWh times the Utility's estimate of the annual kWh consumption of the Customer plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer and meter;
2. GS demand metered less than 1 Mw; $0.04/kWh times the Utility's estimate of the annual kWh consumption of the Customer plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer and meter;
3. GS demand metered equal to or greater than 1 Mw; calculated based on the Revenue/Cost Ration described below;
4. Industrial Customers or projects requiring transmission or substation facilities; calculated based on the Revenue/Cost Ratio described below.

Revenue/Cost Ratio: The comparison between the expected annual revenue to be received from the Customer and the annual cost of serving the Customer. A Revenue/Cost Ration greater than one (1) will result in some level of free extension cost allowance; a Ration less than or equal to one (1) will result in no free extension cost allowance.

<u>Orange and Rockland Utilities – New Jersey, New York, Pennsylvania</u>

1. Allowance for Mandatory Residential Underground Service
   Where the Company is required, by the Commission or a governmental authority having jurisdiction to do so, to provide residential underground service, the cost and expense which the Company must bear, except as otherwise provided in the Rules of the Public Service Commission parts 98, 99, and 100, or as set forth in General information Schedule 5 shall include the material and installation costs for up to a total of 100 feet of single phase underground distribution line (including supply line) and underground service line per dwelling unit served, measured from the Company's existing electric system (from the connection point on the bottom of the riser pole for overhead to underground connections) to each applicant's meter or point of attachment with respect to each residential building. For multiple occupancy buildings the footage allowance for each building shall be up to 100 feet of single phase underground line times the average number of dwelling units per floor of each building. The average number of dwelling units per floor is calculated as follows: total # of units/# floors = number of allowances. If the Company receives an application for underground residential service outside a subdivision, and a governmental authority having jurisdiction to do so has required that the facilities be installed underground, the Company may, if the per-foot cost of installing the necessary facilities will be greater than two times the charges per foot set forth in General Information Schedule 3.H.2, petition the Secretary of the Commission to allow a greater contribution to the cost of installation of the facilities than would otherwise be required.
2. Allowance for Non-Mandatory Residential Underground Service
   Where an applicant requests a residential underground service line in situations other than those as set forth in paragraph (1) above, the cost and expense which the Company must bear shall include the material and installation costs for up to 500 or 300 feet of overhead distribution line, measured from the Company's existing electric system (from the connection point on the bottom of the riser pole for overhead to underground connections) to each applicant's meter or point of attachment with respect to each residential building.

Public Service of New Hampshire – New Hampshire

There is no company policy on what should be underground. However, PSNH does offer the option to customers/developers to locate their developments and services underground. Many communities in New Hampshire have town ordinances requiring underground construction for new residential and commercial developments. Costs in excess of overhead construction are borne by the developer/customer.

Southern California Edison – California

We are continuing to install new UG cable systems; however, we are attempting to pursue padmount installations instead of subsurface/vault installations.

We Energies – Michigan, Wisconsin

Underground construction is used for new subdivisions designs, where existing underground facilities exist, or when determined to be the best overall design in terms of expected reliability performance and life-cycle cost.

Western Massachusetts Electric – Massachusetts

Customers may request underground supply for new residential and commercial installations. The Customer would pay a differential average cost between overhead and underground construction and be required to install some infrastructure (i.e. conduits, transformer pads).

Appendix C: Utility Policies for Converting Existing Overhead Facilities to Underground

Ameren – Illinois

Existing Customers who are presently served by adequate electrical facilities, but request Company to relocate, convert, or in some other manner modify these facilities will reimburse the Company if Company, at its discretion, agrees to make the requested changes. At Company's discretion, such charges may be based on either actual costs or standard job estimation calculations incurred for such work.

When a relocation or modification is done in conjunction with other system expansion or excess facilities requested by Customer, all applicable provisions of each section shall apply. Types of modifications that may fall under this provision include, but are not limited to: 1. Overhead to underground or underground to overhead conversions.

Allegheny Energy – Maryland, Pennsylvania, West Virginia, Virginia

Customer pays for the cost of converting overhead facilities to underground. Customer must also perform trenching, provide conduit, and do all backfilling.

Connecticut Light & Power Company – Connecticut

The standard primary design is overhead, open wire construction. Underground construction may be justified under the following circumstances: In urban areas, where no overhead facilities exist; in a defined new development or primary service; for highway or transmission line crossings; where outside agencies or parties are willing to pay the entire cost of undergrounding existing facilities.

1. A designated underground area is defined as an urban area, where no overhead facilities exist because of clearance problems, circuit congestion, or space limitations. A conventional duct/manhole system shall be used. Configurations of six ducts or 12 ducts shall be used based on the ultimate circuit loading in the immediate vicinity as well as consideration for circuits routed to adjacent areas. Consult **DTR Section 73** for standard duct configurations.
2. In a new residential, commercial, or industrial development, where the developer is willing to pay the differential cost between overhead and underground service, direct buried construction shall be used. This includes primary services. However, in some instances, all or part of a development may require ducts and manholes due to poor backfill conditions or to multiplicity of circuits.
3. For highway and transmission line crossings, where overhead facilities are not feasible, underground cable in a duct or ducts is the preferred design. In these cases, at least one spare duct per cable should be included in the installation where practical. If cable length exceeds 500 feet, a spare cable should be installed with switching to allow its use quickly if full–load tie capability does not exist.
4. When the Company is requested by an outside agency or private party to place existing overhead facilities below grade, the following rules should apply: The minimum length to be considered is 1000 feet, unless contiguous with existing underground construction; the construction will be standard duct/manhole design, utilizing a minimum of 6 – 5″ concrete encased ducts and 5′ x 10′ manholes; if full-load tie capability does not exist beyond subject area then a second cable must be

installed as a backup; if underground construction exists within 1000 feet on either side of proposed construction, then the new construction must be made contiguous with the existing construction.

These guidelines are designed to mitigate the negative effects of frequent changes from overhead to underground construction. All construction listed above shall be considered necessary and 100% reimbursable. This guideline would also apply if below grade construction is requested on a new or existing through street when a line extension is required.

Detroit Edison – Michigan

The Company will not undertake the replacement of existing overhead lines and above-surface equipment with underground installations or provide underground installations for transmission lines, sub-transmission lines, distribution feeders, and above-surface electric equipment associated with switching stations, except where agreements for reimbursement are made in accordance with MPSC R-460.516, "Replacement of Existing Overhead Facilities." The general policy of the Company is that real estate developers, property owners, or other applicants for underground service shall make a non-refundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.

Duke Energy Carolinas – North Carolina, South Carolina

CONVERSION TO UNDERGROUND

The Company will replace an existing overhead distribution system with an underground system in an existing residential development or other area under the following terms and conditions:

1. The Company shall place facilities underground by an agreement with the requesting persons which provides for payment of a nonrefundable, contribution-in-aid-of-construction as follows:
    a. When the existing overhead distribution system is not adequate to supply the customer's load due to added electrical load, the contribution in aid of construction shall be equal to the cost difference between comparable overhead and underground facilities.
    b. When the existing overhead distribution system is adequate to supply the customer's load, the contribution in aid of construction shall be equal to the cost of comparable underground facilities, less any salvage value of the overhead system.
2. Preliminary engineering studies are necessary to determine the approximate costs of replacing overhead with underground facilities. Persons requesting replacement of such facilities shall pay, prior to commencement of such studies by the Company, a good faith, nonrefundable deposit in an amount of $100 for each 600 feet of front lot lines for residential development studies, and, for studies of all other service areas, the estimated cost of the preliminary engineering study. If the replacement is undertaken following completion of such studies, actual costs, including preliminary engineering studies, will be charged and credit will be given for the estimated costs, or deposit, which was advanced.
3. The Company need not replace existing overhead systems with underground facilities, except individual services from pole to residence, unless at least one block or 600' of front lot line is involved, whichever is less.
4. All customers served directly from the specific section of line or in the area to be replaced with underground facilities shall agree to the conditions outlined for replacement of overhead facilities.

5. Owners shall arrange the wiring of their structures to receive underground service at meter locations which allow unimpeded installation of the underground service facilities.

Overhead to Underground Conversion Plan for Municipalities – (Pilot)

AVAILABILITY – Available on an experimental basis, at the Company's option to up to three municipalities where Duke Energy Carolinas, LLC and the municipality have entered into a franchise agreement. The initial term of this pilot is three years.

GENERAL PROVISIONS – This program provides a mechanism to defray the costs of converting overhead electric distribution facilities to underground facilities under the Company's Underground Distribution Installation Plan under the following provisions:

- Each participating municipality will enter into a separate agreement for service under this program which may be an addendum to, or incorporated into, the franchise agreement.
- The cost of overhead conversion projects under this program shall be funded by a Company Fund and a Municipality Matching Fund whereby the Company and the municipality shall commit matching contributions up to 0.5% of the Company's taxable gross receipts from the business of furnishing electricity within the municipality.
- The Company Fund contributions shall be paid out on a one-to-one basis with the Municipality Matching Fund as needed to pay the reasonable and necessary costs of converting the Company's facilities from overhead to underground. The costs to be paid from this fund shall include planning, designing, and constructing the necessary Company facilities. The Company Fund and Municipality Matching Fund are not available for the costs of overhead to underground conversion of any other facilities (e.g. telecommunications, cable television) or the property owners' cost to connect to underground facilities.
- Municipalities shall, with input from the Company, establish priorities for overhead to underground conversion projects. Projects will be prioritized based on expected improvement in system service reliability and/or safety and an expected accompanying reduction in operating and maintenance expense. Overhead to underground conversion projects for aesthetic reasons, or those associated with redevelopment efforts, are not eligible for the Company's matching funds under this program.
- Unexpended amounts of the Company's Match not used in a given year shall remain in the fund and may be used prior to the end of the pilot.
- Overhead to underground facility conversions made under this program shall be made in accordance with all other provisions of the Company's Underground Distribution Installation Plan and the Company's design practices.
- The Company shall not begin construction of an overhead to underground conversion project under this program until the municipality's matching funds are received and all necessary permits and rights of way are provided.

Entergy – Arkansas, Louisiana, Mississippi, Texas

Generally, such conversions are done only at the request of a specific customer, and only after the customer pays the entire conversion cost.

E ON US – Kentucky, Virginia

Customer pays total conversion costs including design and installation of underground and removal of existing overhead.

Hawaiian Electric – Hawaii

When mutually agreed upon by the customer or applicant and the Company, overhead facilities will be replaced with underground facilities, provided the customer or applicant requesting the change makes a contribution of the estimated cost installed of the underground facilities less the estimated net salvage of the overhead facilities removed.

NorthWestern Energy – Montana

When electric Customers request a conversion of existing overhead electrical facilities to underground facilities, Customer shall make a nonrefundable contribution to the Utility equal to the cost to the Utility of the underground installation after an allowance is made for the net salvage value of materials removed after deducting from such salvage the cost of removing the same. Whenever, under the provisions of this Rule, an advance or contribution is required, or a refund is made on any such advance or contribution, such advance contribution or refund shall be increased by a factor of 30 percent. This increase is to offset the effect of income taxes imposed by the Tax Reform Act of 1986. This income tax surcharge is not applicable where such contributions or advances are the result of highway relocations.

It is NorthWestern Energy's policy to not place 161 kV and 230 kV transmission lines underground. The placement of 50 kV through 115 kV transmission lines underground will be considered on a case-by-case basis. Where requests for placing transmission facilities underground are made primarily for aesthetic reasons, the customer or requesting party will pay for the costs incurred to place the lines underground.

Public Service of New Hampshire – New Hampshire

The customer is responsible for all costs in excess of overhead construction costs

Southern California Edison – California

Rule 20 - Replacement of Overhead with Underground Electric Facilities

(Note: only section A of Rule 20 is provided below)

A. SCE will, at its expense, replace its existing overhead electric facilities with underground electric facilities along public streets and roads, and on public lands and private property across which rights-of-way satisfactory to SCE have been obtained by SCE, provided that:

   1. The governing body of the city or county in which such electric facilities are and will be located has:

      a. Determined, after consultation with SCE and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons: Such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities; the street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic; the street or road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public; or the street or road or right-of-way is considered an arterial street or major collector road, as defined in the Governor's Office of Planning and Research General Plan Guidelines.

b. Adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located requiring, among other things, that all existing overhead communication and electric distribution facilities in such district shall be removed, that each property served from such electric overhead facilities shall have installed, in accordance with SCE's rules for underground service, all electrical facility changes on the premises necessary to receive service from the underground facilities of SCE as soon as it is available, and authorizing SCE to discontinue its overhead service.

We Energies – Michigan, Wisconsin

Distribution Planning, Protection and Reliability Groups are responsible for assessing the performance of existing overhead and underground systems. Decisions to convert existing overhead facilities to underground construction are made on a case-by-case basis in concert with expected reliability targets and standard designs.

Western Massachusetts Electric – Massachusetts

For specific customer, i.e. non municipal requests, the Customer would pay the full cost to underground and existing overhead system. For municipal requests, a municipal vote is required and the cost for undergrounding is recovered through a rate addition paid by residents of the municipality. We discourage this practice as it raises rates and may result in longer restoration times.

Appendix D: State Undergrounding Studies

2009 – Louisiana

Title Unknown (Public Service Commission report on burying Louisiana's utility lines)
2009 – Louisiana, Not available to public.

2009, April 21 – Houston, Texas

Electric Service Reliability in the Houston Region, Mayor's Task Force Report
Executive Summary:

- After landfall of Hurricane Ike in September 2008, the electrical grid in the greater Houston area failed broadly, causing personal hardship and economic loss to residents and businesses in our area. Approximately 3.5 million people were without electrical power in the immediate aftermath of the storm, and it was fully two weeks before electrical power was restored to many homes and businesses in the region. Coming only three years after a similar, although less pervasive, power outage in the aftermath of Hurricane Rita, the citizens of Houston, along with local media and civic leaders, began a dialog about our regional electrical grid: Is it overly fragile? Should we take measures to harden its infrastructure against storm-related failure? Are there new technologies that might enhance the resiliency of our electrical power delivery system? Are there strategies we should encourage for citizens who want to prepare their own environment for the next outage?
- In October of 2008, Mayor Bill White convened a Task Force to explore the options for hardening our electrical grid against catastrophic failure during hurricane events and, by extension, against lesser weather events or terrorist actions. The Task Force was comprised of members from government, utility, business, regulatory, and environmental technology backgrounds. CenterPoint Energy, the regional transmission and distribution utility, was an active participant. The Task Force convened monthly and assigned research tasks between meetings, attempting to cast a wide net to capture expert opinion on a variety of topics, including the cause of Houston's recent grid failures, and strategies to increase resilience and recovery in anticipation of future storm events.
- The conclusions of the Task Force related to undergrounding are summarized here:
  - The cause of grid failure during Hurricane Ike was predominantly falling trees and tree limbs across power distribution and service lines – rather than the wind or water directly. No high-voltage transmission lines failed, no substations failed and less than 1% of the distribution system's one million wooden poles were knocked out of commission, suggesting that improved vegetation management will have a more significant effect on reliability than would replacement of wooden poles with steel or concrete.
  - The cost of undergrounding the existing distribution infrastructure is prohibitive. It would cost an estimated $35 billion to bury the cables of the entire regional distribution system, which is cost prohibitive. Undergrounding has other costs in traffic congestion and business losses as rights-of-way are excavated. Furthermore, while undergrounding reduces risk of grid failure due to wind damage, it increases vulnerability to flood damage such as that seen in Tropical Storm Allison in 2001.

- Some selective undergrounding makes sense. When developing new land parcels, undergrounding is economically rational: earthmoving is underway, and disruption to existing infrastructure is minimal. Ninety percent of all new residential distribution facilities since 1990 have been placed underground. Also, critical facilities that serve a critical role in disaster recovery might be given priority for selective undergrounding, when excavation for some other capital purpose (sewer, watermain, or roadbed replacement) is otherwise required.

2008, June 30 – Oklahoma

Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma, Prepared and Submitted by Oklahoma Corporation Commission Public Utility Division Staff

Excerpt of the Executive Summary:

- The purpose of this report is to gather, develop, and provide the Oklahoma Corporation Commission with relevant information to assist the Commissioners in making an informed decision as to what actions, if any, should be taken regarding future plans and development to protect electric plants in the State of Oklahoma from weather events to assure reliable service for state electric customers.
- The need for this study surfaced when on December 8 and continuing through December 10, 2007, the State of Oklahoma experienced one of the most disruptive ice storms in the state's history. The Commission's Customer Service Division reported the storm resulted in more than 600,000 homes and businesses across the state being without electric service. Many customers were without electric service for several days while others were without service for a week or more. This storm followed by less than 12 months another "storm of the century" in which rural portions of Oklahoma suffered even greater physical damage to the electricity infrastructure, although loss of life was less and the homes and businesses affected were fewer.
- Following this storm and cleanup efforts, the Oklahoma Corporation Commission conducted a meeting on January 7, 2008, to discuss the impact of severe storms on state utilities. More specifically, the meeting was conducted to discuss advantages, disadvantages, and feasibility of moving more aggressively to bury power lines, as well as the impact burying electric lines may have on electric customers across the State of Oklahoma.
- Staff's review of this issue also included meeting on January 10 and January 15, 2008 with representatives from Oklahoma's two largest investor-owned electric utilities, Public Service Company of Oklahoma (PSO) and Oklahoma Gas and Electric Company (OG&E), to gain additional insight about the potential of undergrounding electric transmission and distribution facilities. On January 16, 2008, Staff issued an extensive data request to all retail electric utilities and cooperatives operating in the State of Oklahoma, in order to gain additional information about utility operations and activities affecting utility response to storm outages. The Staff also met with members of the Oklahoma Climatological Survey on February 1, 2008, to discuss the impact of severe weather conditions and the frequency of such conditions, which will likely continue to have a negative impact on Oklahoma's electrical plant and Oklahoma customers.
- Information gathered from the various in-depth commission studies that were analyzed, clearly indicated that requiring electric utilities to underground all of their facilities is generally not a feasible solution. The cost to underground all transmission and distribution facilities in any state would likely run into the billions of dollars, and the potential impact on customers would be significant, to say the least approaching thousands of dollars per customer.

- No public utility commission has found a funding mechanism that will permit undergrounding of electric facilities to be completed on any sort of universal or fast track basis. However, commissions have attacked this problem by addressing very specific parts of the electric grid, e.g., poorly performing circuits, lines along road rights of way undergoing construction, all secondary line extensions, etc.
- The potential financial impact of undergrounding all electric facilities is generally accepted to be in the billions of dollars, which would cause an enormous and impractical burden to customers. For example, there are approximately 8,551 miles of main (or feeder) distribution lines and approximately 34,600 miles of lateral distribution lines in Oklahoma. Using information supplied in response to the Staff's January 16, 2008 data request, the cost to underground existing overhead main and lateral distribution lines is estimated to be between $435,000 and $2.5 million per mile, depending on certain conditions, resulting in an estimated statewide cost of $30.5 billion to underground only distribution lines.
- The $30.5 billion does not include burial of transmission lines, which require special treatment due to heat-dissipation issues not present with distribution lines. Oklahoma has approximately 7,500 miles of transmission facilities. Oklahoma electric utilities had a difficult task estimating the cost to underground these facilities in their response to Staff's data requests.
- To put these numbers into perspective, consider that the State Equalization Board's determination of funds available for legislative appropriation in Fiscal Year 2009 is approximately $7 billion, making the estimated cost of burying all electric lines in Oklahoma more than six times the annual State budget. The cost is also roughly four times the total value of all centrally assessed public utility assets in the State, as determined by the Tax Commission. Monthly electric bills would have to increase $80 to $260 for 30 years to pay for the cost of burial; contingent upon how much of the electric network is placed underground.

2008, May 21 – Florida

Undergrounding Assessment Phase 3 Report: Ex Ante Cost and Benefit Modeling, by Richard Brown, Quanta Technology

Excerpt of the Executive Summary:

- This report is the Phase 3 deliverable of a project awarded in response to RFP #U-1 issued by the Florida Electric Utilities. RFP #U-1 was a result of Florida Public Service Commission Order No. PSC-06-0351-PAA-EI, which directs each investor-owned electric utility in Florida to establish a plan that increases collaborative research to further the development of storm-resilient electric utility infrastructure and technologies that reduce storm restoration costs and interruptions to customers. Municipal electric and cooperative electric utilities are participating voluntarily.
- The scope of the overall project (all three phases) is to investigate the implications of converting overhead electric distribution systems in Florida to underground (referred to as undergrounding).
- Phase 3 develops and tests a methodology for analyzing the costs and benefits of specific undergrounding proposals in Florida. The methodology is separated into two basic components: normal weather assessment and hurricane assessment. The normal weather model includes the basic cost of utility capital and operational cost information. It also includes high-level reliability information that allows for the calculation of customer interruption information and related costs.
- It is well-known that the conversion of overhead electric distribution systems to underground is costly, and these costs almost always exceed quantifiable benefits. This conclusion is reached

consistently in many reports that range from state-wide studies to very small projects. However, there is no consistent approach has been used to compute the costs and benefits of proposed undergrounding projects, making studies difficult to interpret and use for making decisions.

- As more areas in Florida begin to explore the possibility of underground conversion, it becomes increasingly desirable to have a consistent methodology to assess the associated costs and benefits. Results from a trusted approach can provide insight, lead to better projects, aid in customers communicating with utilities, and potentially help guide certain regulatory approaches.
- This report has presented a methodology capable of computing the costs and benefits of potential undergrounding projects. The methodology can also be used to compute the costs and benefits of other activities that have an impact on hurricane performance such as the hardening of overhead systems. The methodology used a detailed simulation with the following components: hurricane module, equipment damage module, restoration module, and cost-benefit module. This methodology has been implemented in a spreadsheet application so that it can be easily used by interested parties.
- The conversion of overhead electric infrastructure to underground is of interest around the country and around the world. Often times underground conversion proposals are either pursued or rejected without a systematic analysis of costs and benefits. The methodology presented in this report is an attempt to add consistency, rigor, and thoroughness to these types of analyses. At present, the methodology is specific to the state of Florida, but the general approach is valid wherever extreme weather events have the potential to wreck havoc on electricity infrastructure.

2007, August 6 – Florida

Undergrounding Assessment Phase 1 Report: Undergrounding case Studies, by Richard Brown, InfraSource Technology

Executive Summary:

- This report presents the results of Phase 2 of a three phase project to investigate the implications of converting overhead electric distribution systems in Florida to underground (referred to as undergrounding). The purpose of Phase 2 is to examine the cost and benefits of actual undergrounding projects that have been completed. The focus is to identify the drivers of each project; discuss the challenges of each project; and to collect data that can serve as a real-world basis for *ex ante* modeling in Phase 3.
- A review of the case studies reaches the same conclusion reached in Phase 1 literature review: the initial cost to convert overhead distribution to underground is high, and there is insufficient data to show that this high cost is 100% justifiable by quantifiable benefits such as reduce O&M cost saving and reduced hurricane damage. Increased data collection can potentially increase the amount of quantifiable benefits, but it is unlikely that these benefits will 100% justify high initial cost, except potentially in a situation where an undergrounded system is struck by multiple severe hurricanes. For all of these case studies, by far the strongest reason for undergrounding is to improve the aesthetics of the area. Additional observations relating to these case studies include:
    - All case studies occurred in coastal areas.
    - Two of the four projects were done in conjunction with roadway widening projects.
    - More circuit miles of underground are sometimes built than the original overhead amount. This is typically to create an underground loop that increases operational flexibility and the ability to respond to faults.

  - Cost per circuit mile figures correspond to those identified in Phase 1 literature search.
  - Cost per customers varies widely based on both the cost per circuit mile and the amount of high density housing such as high rise condominiums.
- Not much data is available on the impact of the case studies on non-storm reliability and hurricane performance. The little data that is available indicates that non-storm reliability is not significantly different after undergrounding and that hurricane reliability of underground systems is not perfect to storm surge damage.
- For these case studies, there is an extensive amount of project description and project cost data, but limited avoided cost and benefit data. These case studies can certainly be used as an input for an ex ante model, but there is not sufficient data to compare the output of the ex ante model to historical realized benefits. There is not even enough data to determine upper and lower bounds of potential results. At this point, any ex ante model that is developed, such as one to be developed in Phase 3, must be justified by its model assumptions rather than by its ability to replicate realized benefits from any of these case studies.

2007, February 28 – Florida

Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion, by Richard Brown, InfraSource Technology
Executive Summary:

- The conversion of overhead electric power distribution facilities to underground has been a topic of discussion in Florida for more than twenty years. The topic has been studied, discussed, debated many times at the state, municipal, and local levels. Overhead construction is the standard in Florida, but all investor-owned utilities are required to have a process where customers can opt to underground existing overhead service by paying the incremental cost. For municipals and cooperative, the decision to underground is left to the local citizen boards.
- This report presents the results of a review of relevant previous undergrounding studies done in Florida as well as literature on the subject from throughout the US and around the world. This review finds that the conversion of overhead electrical distribution systems to underground is costly, and these cost are far in excess of the quantifiable benefits presented in existing studies, except in the rare case where the facilities provide particularly high reliability gains or otherwise have a higher than average impact on the community goals.
- This conclusion is reached consistently in many reports, which almost universally compare the initial cost of undergrounding to the expected quantifiable benefits. No prior cost benefit study recommends broad-based undergrounding, but several recommend targeted undergrounding to achieve specific community goals.

2005, January 7 – Virginia

Placement of Utility Distribution Lines Underground, Report to the State Corporate Commission
Executive Summary:

- The primary advantages of underground circuits are improved aesthetic and the overall improved reliability. In addition, underground rights-of-way require little tree trimming and underground facilities are much less susceptible to motor vehicle accidents. However, the relocation of currently existing overhead lines would result in the tremendous cost and significant disruption. In addition, a major relocation initiative could take decades to complete and encounter complications regarding underground damages prevention and attainment of new easements.

- The cost associated with the placement of the currently existing overhead electric utility distribution facilities underground was estimated by utilities to be over $80 billion. The resultant annualized revenue requirement on a per customer basis would be approximately $3,000.
- The potential benefits, both to the utilities and to the economy, resulting from the elimination of tree trimming maintenance, vehicle accidents, post storm restoration and lost sales during outages, do not appear to be sufficient to offset the initial construction costs associated with a comprehensive program to relocate the currently existing overhead utility distribution lines to underground. The placement of all new distribution line underground, though not as costly, is also probably not cost effective.
- Regardless of the funding options available for a comprehensive statewide initiative, the cost would be paid ultimately by consumers, either directly or indirectly, in the form of prices, taxes, or utility rates. Anecdotal evidence suggests that consumers might not be willing to pay the cost necessary to fund a comprehensive statewide initiative.
- Based on our research and analysis and input from interested parties, the wholesale relocation of the currently existing overhead utility distribution lines and placement of all new utility distribution lines underground is probably reasonable. The economic effects of such an effort on state and local governments or utilities, and ultimately customers, would be significant.

2003, December 30 – Maryland

Task Force to Study Moving Overhead Utilities Lines Underground
Finding:

- No new laws are necessary to facilitate undergrounding projects
- Improved aesthetics is the primary reason to underground overhead utilities
- Undergrounding can enhance public safety
- Undergrounding remains very expensive – cost is the primary obstacle
- Economies of scale can be realized when undergrounding if all overhead utilities (electric, cable TV, phone) are relocated at the same time
- Further saving can be realized if undergrounding is done in connection with planned infrastructure improvements to roadways or other underground utilities
- Undergrounding is desirable in certain instances
- While the frequency of outages may be significantly improved in the short-term, the long-term reliability of undergrounding is more questionable
- Underground cables are more susceptible to damage during excavation activities
- While underground outages may occur less frequently, they generally take longer to repair

2003, November 21 – North Carolina

The Feasibility of Placing Electric Distribution Facilities Underground, Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force

Executive Summary:

- In early December 2002, a major ice storm blanketed much of North Carolina with up to one inch of ice, causing an unprecedented power outage to approximately two million electric utility customers. In the immediate aftermath of the storm, the public expressed considerable interest in burying all overhead power lines in the state. The Public Staff responded by investigating the desirability and feasibility of converting the existing overhead lines of the state's three investor-owned electric utilities – Duke Power ("Duke"), Progress Energy Carolinas ("Progress Energy"), and Dominion North Carolina Power ("Dominion") (collectively, "the Utilities") – to underground. Since the majority of the damage sustained in severe weather events usually involves distribution rather than transmission lines, the Public Staff's investigation focused on undergrounding this portion of the electrical power delivery system. The primary purpose of this report is to present the results of that investigation.
- The investigation consisted of (1) comparing the operational advantages and disadvantages of overhead and underground power distribution systems; (2) estimating and comparing the capital costs of converting overhead lines to underground, along with the differences in operation and maintenance (O&M) costs for the two types of systems; (3) estimating the time and human resources required to bury underground lines; (4) identifying potential additional costs to customers, municipalities, and other utilities that may result from conversion; and (5) exploring options for financing conversion projects. The Utilities provided valuable assistance throughout the investigation, and the Public Staff gratefully acknowledges their contribution to this report.
- The Public Staff has determined that replacing the existing overhead distribution lines of the Utilities with underground lines would be prohibitively expensive. Such an undertaking would cost approximately $41 billion, nearly six times the net book value of the Utilities' current distribution assets, and would require approximately 25 years to complete. The ultimate impact of the capital costs alone on an average residential customer's monthly electric bill would be an increase of more than 125%. Rates would also be impacted by the higher O&M costs associated with direct-buried underground systems, particularly in urban areas, where underground conductors are four times more costly to maintain than overhead facilities. In addition to the impact on the cost of providing utility service, conversion to underground would impose costs on individual customers, municipalities, and other utilities. While these costs have not been quantified, they could be significant.
- The Public Staff has also determined that underground facilities are not without their disadvantages. Although underground systems are more reliable than overhead systems under normal weather conditions, they are not impervious to damage, and the repair time for underground systems is almost 60% longer than for overhead systems when damage does occur. Consequently, the Public Staff does not recommend that the Utilities undertake the wholesale conversion of their overhead distribution systems to underground.
- The Public Staff does recommend, however, that each of the Utilities (1) identify the overhead facilities in each region it serves that repeatedly experience reliability problems based on measures such as the number of outages or number of customer-hours out of service, (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities, and, if so, (3) develop a plan for converting those facilities to underground in an orderly and efficient manner, taking into account the outage histories and the impact on service reliability. Such a plan

might include a policy similar to that of Dominion Virginia Power of annually identifying the "worst 10 circuits" and "worst 10 devices" in each of its regions and taking appropriate steps to improve or replace each of these circuits and devices.

- In the meantime, the Public Staff recommends that the Utilities continue their current practices of (1) placing new facilities underground when the additional revenues cover the costs or the cost differential is recovered through a contribution in aid of construction, (2) replacing existing overhead facilities with underground facilities when the requesting party pays the conversion costs, and (3) replacing overhead facilities with underground facilities in urban areas where factors such as load density and physical congestion make service impractical from overhead feeders.

1999, December 30 – Maryland

Undergrounding Electric Utility Lines in Maryland, by Exeter Associates, Inc
Findings:

- The utilities' transmission system, sub-transmission systems, substations were largely unaffected by ice storms and Hurricane Floyd and significant efforts for these components were not required.
- Almost all of the restoration efforts related to the ice storm and Hurricane Floyd were directed toward distribution mains, distribution laterals from mains, secondary conductors, and service conductors directly connecting end users.
- Relative to overhead lines, underground lines offer advantages in terms of aesthetics; reduced susceptibility to damage from wind, ice, and vehicles; reduced operation and maintenance cost; minimization of inadvertent contact with lines by people and animals.
- Relative to overhead lines, underground lines present disadvantages in terms of installation costs; power-carrying capacity; the ease (and cost) of locating and correcting problems on the lines; the ease of performing system upgrades; and certain ancillary concerns such as traffic disruptions during installation, arranging for placement of above-ground transformers on private property, and possible impacts on above-ground utility systems, e.g., telephone and cable television.
- Assuming an average cost per mile of $450,000 for undergrounding the existing OH distribution system of PEPCO and BGE, the cost of underground would result in substantial increase in electric utility rates if funding for undergrounding were to be collected fully from distribution service ratepayers. Increases in residential rates are estimated to be approximately 36 percent for BGE customers (or an increase of approximately $340 per year) and 46 percent for PEPCO customers (or an increase of approximately $415 per year).
- Cost for undergrounding existing overhead lines vary significantly depending on the specific characteristics of the area, such as topography, geology, and land use.
- Completion of conversion to UG lines for substantial portions of the OH distribution system will likely require 15 to 20 years for planning, design, and construction.

1999, December – Hawaii
Undergrounding Public Utility Lines, by Pamela Martin, for Legislative Reference Bureau
Executive Summary:

- This report examines the policies and issues of undergrounding public utility lines. The policies and issues discussed in Chapter 2 have been categorized into seven topics: (1) type of line; (2) location; (3) benefits of undergrounding; (4) costs; (5) public sentiment; (6) technological issues; and (7) legal matters. The discussions within each topic address related issues and refer to assorted documents that may be of interest in those particular areas. Chapter 3 of this report reviews the treatment of undergrounding in other jurisdictions. Finally, Chapter 4 discusses the theory and process of public utility actions and suggests alternatives to address some of the problematic issues identified in Chapter 2. Legislation is included in the appendices for all suggestions.

- While all of the issues discussed are relevant, the issues of benefits and cost have the most significance with regard to requirements of the current law in evaluating whether or not electrical lines should be underground in section 269-27.6, Hawaii Revised Statutes. The structure of the law requires a balancing of benefits and costs but without a standard to measure benefits, it is almost impossible to accurately compare these issues. The study suggests that the Consumer Advocate should be provided with the tools to measure benefits that include the valuation of certain intangibles. This measurement of externalities is necessary to complete the current analysis required under the law. Costs are considered from the perspectives of consumers, the utilities, and government. The study also looks at cooperative funding from all entities.
- Regarding plans for the conversion of overhead lines to underground, this report focuses on the solutions presented by the California Public Utility Commission. The California PUC has actively pursued the conversion of overhead utility lines to underground for thirty years by establishing guidelines for counties and requiring utilities to participate by allocating as much as two percent of a utility's gross revenues to undergrounding. Counties and consumers are expected to share costs according to locations and criteria set by both the California PUC and counties.
- The final analysis of the issues highlights the need to develop the measurement of intangibles; create independent review throughout the process in order to reduce built-in bias; establish clearer communication lines between consumers and PUC operations; promote quality consumer participation in the process; encourage settlement through alternative dispute resolution; and provide for safety through the establishment of a one-call system.

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