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OCC EXHIBIT NO. 2

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)	Case No. 08-935-EL-SSO

PUBLIC VERSION

DIRECT TESTIMONY

of

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ON BEHALF OF
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
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September 29, 2008

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, ADDRESS AND POSITION.

A1. My name is David Cleaver. My business address is 10 West Broad Street, Suite 1800, Columbus, Ohio, 43215-3485. I am employed by the Office of the Ohio Consumers' Counsel ("OCC" or "Consumers' Counsel") as a senior electrical engineer-energy analyst.

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I graduated from the University of Kentucky in 1973 with a Bachelor of Science degree in Electrical Engineering and from Morehead State University in 1987 with a Masters degree in Business Administration. I am also a registered professional engineer in the state of Ohio and Kentucky and hold certifications in Ohio as a Chief Building Official and a Residential Building Official. I have over 22 years of experience in the electric utility industry working for Kentucky Utilities Company as an Electrical Engineer from 1973-1977, Kentucky Power Company as a Distribution Engineer and then as a Power Engineer from 1977-1985, and American Electric Power Service Corporation as a Project Management & Construction Engineer and then as a Cost Control Engineer from 1985-1995. I have spent the past twelve years in the public sector working for the City of Columbus and the State of Ohio. I started at the City of Columbus in 1996 as an electrical engineering plan examiner and then was promoted in 1997 to the position of Supervisor of the Plans Examination & Inspection Section of the

Building Services Department, a unit totaling approximately 85 employees comprised of architects, engineers and building inspectors. In 2002, I took a similar position with the Division of Industrial Compliance as the electrical engineering plans examiner for the State of Ohio.

Q3. HOW MANY YEARS OF EXPERIENCE DO YOU HAVE WORKING DIRECTLY IN THE ELECTRIC UTILITY INDUSTRY?

A3. I have over 22 years of experience working directly for investor-owned electric utility companies. For the first fifteen years, I worked extensively on the engineering, design, and construction of new electrical distribution systems as well as the analysis and resolution of distribution circuit performance and reliability problems such as circuit overloads and unbalanced phases. In addition to providing solutions and action programs to solve reliability problems, I was involved directly with the implementation of operation and maintenance procedures to correct items such as voltage flicker and momentary outages. During the following seven-year period, my responsibilities were expanded to also include the engineering, design, construction and maintenance activities associated with transmission lines and stations (69 kV and above) and power plant systems.

Q4. WHAT PORTIONS OF YOUR WORK EXPERIENCE ARE RELATED TO THE DELIVERY OF RELIABLE ELECTRIC SERVICE?

A4. All of my work experience, spanning more than thirty years and involving all facets of the electric utility industry, are either directly or indirectly related to the delivery of reliable electric service. Because electric transmission and distribution systems are designed to last many decades and because utility companies must "keep the lights on" in order to meet their obligation to serve their customers and to make a profit, reliable service is the fundamental guiding principle for all engineering activities.

Q5. WOULD YOU PLEASE PROVIDE SOME EXAMPLES OF YOUR WORK EXPERIENCE CONCENTRATING IN THE AREA OF ELECTRICAL DISTRIBUTION SYSTEMS?

A5. I have extensive experience in the engineering, design, and construction of underground distribution systems. This experience includes the construction of the underground network grid serving downtown Lexington, Kentucky as well as numerous underground residential distribution ("URD") systems for Kentucky Utilities ("KU") Company. I was considered to be KU's URD utility expert and was charged with responsibility of specifying equipment, creating a URD cable testing program, and recommending operation and maintenance policies and practices to company management. In the area of overhead distribution systems, I have performed as an engineer and as an engineering supervisor responsible for the design and construction of new lines and substations such as a 12kV to 34.5kV conversion project in Ashland, Kentucky. I have performed a variety of technical studies such as system capacity/overload studies and cold load pickup studies which are needed to properly operate and maintain distribution lines and substations. I have both performed and supervised the performance technical studies such as load flow analyses, voltage fluctuation studies, fault studies, and analyzed outage cause data to determine the adequacy of distribution facilities. Additionally, I have had direct oversight of numerous outage restoration activities during major storms as well as the supervision of routine pole and a line/equipment inspection programs. Lastly, I have been directly responsible for a vegetation management program which includes utility employed arborists and contract tree trimming crews.

Q6. DID ANY OF YOUR WORK EXPERIENCE IN THE NON-UTILITY PUBLIC SECTOR ALSO INVOLVE THE RELIABILITY OF ELECTRICAL DISTRIBUTION SYSTEMS?

A6. Yes, it did.

Q7. WOULD YOU PLEASE PROVIDE SOME EXAMPLES OF THIS RELIABILITY-RELATED WORK EXPERIENCE?

A7. While working for both the City of Columbus and the State of Ohio, I reviewed and approved plans for electrical distribution systems for very large industrial customers, universities, penitentiaries, and other public institutions who owned their own electrical distribution facilities. I analyzed these entities' plans for compliance with the structural and electrical requirements of the Ohio Building Code ("OBC") which are the minimum standards for new construction. The projects which I reviewed included overhead and underground lines, substations, transformers, voltage regulators, relays, switches, circuit breakers, capacitors, reclosers, and a variety of other equipment which was very similar to that installed by electric utility companies. In addition, I continued to analyze outage report data and one-line circuit diagrams of different electric utility companies to evaluate their service reliability. This information was provided by the electric utility company to one of the large entities mentioned above (i.e. Ohio University) who owned their own distribution facilities. This analysis was necessary to determine if and when a second source of emergency power (such as an emergency generator or a second feed from the utility) was required by the OBC for a high risk facility such as a high-rise apartment building or a hospital. The standard for reliability contained in the OBC is extremely high because these high-risk facilities contain life safety systems such as emergency lighting, sprinkler systems, fire alarms systems, smoke control systems, operating rooms, elevators, etc. An example of this high standard would be a hospital which was served by a circuit with a reliability measure known as Customer Average Interruption Duration Index ("CAIDI") as low as 90 minutes, but would still be required to install an emergency power system.

Q8. ARE THERE ANY OTHER AREAS OF YOUR WORK EXPERIENCE WHICH ARE RELEVANT TO THIS PROCEEDING?

A8. Yes there are. First, while working for the City of Columbus, I was involved in the review and approval of site plans for large developments of residential and commercial property. This included the coordination of installation of the City's utility infrastructure for sewer, water, and storm water as well as electric and gas utilities. Through this review and approval process, I gained extensive knowledge of the pros and cons of both "rear lot" and "front lot" installation of utility infrastructure. This experience is relevant to the FirstEnergy Companies' witness Schneider's request for a "Rear Lot Reduction Factor" for CEI's SAIDI ("System Average Interruption Duration Index") calculation. Secondly, while working for American Electric Power Service Corporation, I was responsible for providing cost/benefit analysis and scheduling of large capital projects such as those proposed by the FirstEnergy Companies to enhance service reliability. This experience is relevant to the request for a Delivery Service Improvement Rider ("DSI Rider").

Q9. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A9. Yes. I testified in the FirstEnergy Distribution Rate Case, Case No. 07-551-EL-AIR, ("Distribution Rate Case") on behalf of the OCC. That testimony addressed the reliability-related policies and practices that are applied to the distribution systems of the FirstEnergy electric distribution companies.

Q10. WHAT WERE OCC'S RECOMMENDATIONS IN THE DISTRIBUTION RATE CASE RELATIVE TO SERVICE RELIABILITY AND COMPLIANCE WITH ESSS RULES?

A10. OCC made four recommendations related to service reliability and compliance with the PUCO's Electric Service and Safety Standards ("ESSS") that may be found on pages 29-30 in my testimony in the Distribution Rate Case:

1. Due to the problems associated with the Companies' recordkeeping systems, OCC recommended that the Commission require FirstEnergy Companies to use a minimum data retention period of five years.
2. Due to the performance of the FirstEnergy Companies, and particularly that of CEI, in not meeting its service reliability targets and due to problems documented in the Distribution Rate Case Staff Reports concerning the Companies' vegetation management program, OCC recommended the Commission require the Companies implement a performance-based vegetation management program which also addresses problems caused by trees outside the distribution right-of-way.
3. Due to the performance of the FirstEnergy Companies, and particularly that of CEI, in not meeting its service reliability targets, OCC recommended the Commission reflect that under-performance in the allowed rate of return, as addressed in the direct testimony of OCC witness Aster Adams.
4. Due to the problems associated with the FirstEnergy Companies service reliability programs, OCC recommended the Commission use its authority, pursuant to Ohio Revised Code 4905.26, to investigate the sufficiency and adequacy of the FirstEnergy Companies' service quality and to hold a hearing regarding that service quality.

II. PURPOSE OF TESTIMONY

Q11. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THE CURRENT PROCEEDING?

A11. My testimony on behalf of the OCC presents the results of my evaluation of the reliability-related policies and practices that are applied to the distribution systems of the FirstEnergy electric distribution companies (the Cleveland Electric Illuminating Company ("CEI"), Ohio Edison ("OE"), and Toledo Edison ("TE") (collectively, "FirstEnergy Companies" or "Companies")). My testimony will specifically address the portions of the FirstEnergy Companies' Electric Security Plan ("ESP") Application which are related to the electric service reliability performance of their distribution systems. Because the Companies' propose to resolve their pending Distribution Rate Case in their ESP, my testimony will also include OCC's reliability-related recommendations from that distribution rate case. In addition, my testimony will address OCC's position concerning the Companies' proposals in their ESP Application to:

- Implement a DSI Rider,
- Increase or decrease the DSI rider based on the Companies' SAIDI performance indices, and
- Commit over $1 billion to capital investment in their distribution system over five years, from 2009-2013.

Q12. WHAT INFORMATION HAVE YOU REVIEWED IN PREPARING YOUR TESTIMONY?

A12. In preparing my testimony I have reviewed the Company's ESP Application, the testimony of the FirstEnergy Companies' witnesses, responses to OCC's discovery, responses to discovery by other interveners, and responses to Staff data requests. In addition, I have reviewed the Companies' filings, testimony of Companies and PUCO Staff witnesses, responses to OCC's discovery, responses to Staff data requests and the Staff Reports of Investigation in the Distribution Rate Case. Also related to the distribution rate case, I have reviewed the 2007 Focused Assessment of the Cleveland Electric Illuminating Company conducted by UMS Group Inc. ("UMS Report").[1] The sections which I reviewed of the Staff Reports in the Distribution Rate Case were those portions of the three reports for the Companies' prepared by the Public Utilities Commission of Ohio Staff's Service Monitoring and Enforcement Department. Finally, I reviewed the proposed revisions to the ESSS Rules in Case No. 06-653-EL-ORD, which is currently before the Commission.

Q13. PLEASE DESCRIBE THE RECOMMENDATIONS OF THE UMS REPORT AS REFERENCED IN THE STAFF REPORT.

A13. The UMS Report recommended eight short-term actions it believed CEI must take to meet ESSS Rule 10 reliability targets by the end of year 2009:[2] These recommendations include, but are not limited to, an enhanced tree trimming program to address overhanging limbs and structurally weak trees on the feeder

[1] Attachment DWC-1

[2] CEI Staff Report at 77

backbone, a systematized process of determining when to mobilize personnel in anticipation of storms, and full implementation of partial restoration practices when initially servicing customer outages. The UMS recommendations also identified five long-term (i.e. 10-years following 2009) actions which included maintaining capital spending at the level currently planned for 2008 ($84.7 million) for a minimum of 5 years. Finally, the report cited twelve (12) additional recommendations which are identified as desirable but at a lower cost benefit relationship.

Q14. WHAT WAS STAFF'S POSITION ON THE UMS RECOMMENDATIONS?

Q14. Staff recommended that the Commission order FirstEnergy to immediately implement all of the consultant's short-term and long-term recommendations as listed above in accordance with their recommended completion dates. The Staff also recommended that CEI seriously consider implementing the 12 other UMS recommendations and that CEI provide Staff with an implementation schedule for those recommendations the Company plans to implement or a detailed justification for any recommendations the Company does not plan to implement.[3]

[3] CEI Staff Report at 79

III. FIRSTENERGY HAS NOT ADDRESSED THE SERVICE QUALITY ISSUES RAISED BY OCC IN THE DISTRIBUTION RATE CASE.

Q15. AS A RESULT OF YOUR REVIEW IN THIS ESP PROCEEDING, HAS OCC CHANGED ITS POSITION CONCERNING A RECOMMENDED DATA RETENTION PERIOD OF FIVE YEARS?

A15. No. OCC has not changed its position. There has been no indication in the Companies' ESP Application, their testimony, or from any information obtained from discovery in this case which would indicate that the Companies intend to accept OCC's recommendation to retain records for five years. It should be further noted that there has been no indication that the Companies have implemented Staff's recommendation to retain tree trimming records for eight years (equivalent to two four-year tree-trimming cycles). However, the proposed revisions to the ESSS Rules pending before the Commission appears to clarify that the retention period for records at a minimum must match the same time period of the inspection program, i.e. a five-year inspection cycle requires records which span five years. According to the proposed rule for 4901:1-10-27 (E)(4), "Each electric utility and transmission owner shall maintain records sufficient to demonstrate compliance with its transmission and distribution facilities inspection, maintenance, repair, and replacement programs as required by this rule." Depending on the Commission decision of the proposed ESSS Rules, OCC's concerns with FirstEnergy's data retention may be partly resolved.

Q16. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED ITS RECOMMENDATION THAT THE COMPANIES IMPLEMENT AN ENHANCED VEGETATION MANAGEMENT PROGRAM ADDRESSING TREES LOCATED OUTSIDE THE RIGHT-OF-WAY?

A16. No. There has been no indication in the Companies' ESP Application or testimony which would indicate that the Companies intend to accept OCC's recommendation. However, the FirstEnergy Companies have added one enhancement to its vegetation management program whereby the Companies will endeavor to remove overhanging branches from the primary conductor to the sky. This was a badly needed improvement. However, even with this change, OCC still recommends that more enhancements are needed and has therefore not changed its position from the distribution rate case.

Q17. WHAT WERE SOME OF THE PROBLEMS WITH VEGETATION MANAGEMENT THAT WERE CITED IN THE DISTRIBUTION RATE CASE?

A17. Section 4901:1-10-27(E) (1) (f) Right-of-way Vegetation Control requires a written program for vegetation management to verify the Company's 4-year tree trimming program. The Staff Reports in the Distribution Rate Case found that missing records and inaccurate data prevented full verification by Staff that the Company complied with its 4-year tree trimming cycle maintenance program. For example, the Company did not provide the specific time periods (start date/end date) to show when the tree trimming process was actually conducted in each calendar year. Compounding Staff's inability to verify FirstEnergy's use of the 4-year cycle, FirstEnergy also explained that, "For the purposes of data retention, tree trimming records are maintained for one cycle or three years, whichever is the longer duration. In addition, the IVMS (Integrated Vegetation Management System) was implemented in 2003. As such, the records for 2000, 2001, and 2002 are no longer available."[4] As a result, it was difficult for Staff to determine the specific time periods in which all applicable circuits were actually trimmed.

Q18. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED ITS RECOMMENDATION THAT THE COMMISSION LOWER THE COMPANIES' ALLOWED RATE OF RETURN IN DETERMING THE LEVEL OF DISTRIBUTION RATE INCREASE FOR THE COMPANIES?

A18. No. Neither the Companies' ESP Application nor testimony addresses the topic of their current or past performance in meeting reliability targets. In the Distribution Rate Case, OCC recommended that the Commission reflect the Company's under-performance in meeting its reliability targets by lowering the Companies' allowed rate of return. The downward adjustment in the rate of return was addressed in the direct testimony of OCC witness Aster Adams. OCC's position has remained unchanged on this issue.

[4] CEI Staff Report at 67, OE Staff Report at 65, TE Staff Report at 69.

Q19. AS A RESULT OF YOUR REVIEW IN THIS PROCEEDING, HAS OCC CHANGED IS POSITION RECOMMENDING THAT THE COMMISSION ORDER A SEPARATE HEARING CONCERNING FIRSTENERGY'S SERVICE QUALITY?

A19. No. Due to the depth and breadth of the problems associated with FirstEnergy's service reliability programs, OCC has recommended that the Commission utilize its authority, pursuant to Ohio Revised Code 4905.26, to investigate the sufficiency and adequacy of FirstEnergy's service quality and to hold a hearing regarding FirstEnergy's service quality. Proposed changes to the ESSS rules may require the actual filing of an electric utility's reliability targets to the Commission in the future as opposed to merely submitting the targets for Staff's approval. A formal filing should provide a more open process which the OCC argued for in the Distribution Rate Case.

Also, even though I am not an attorney, it is my understanding that portions of Amended Substitute Senate Bill 221 ("SB 221") may also impact this issue since R.C. 4928.02 (E) states the policy of the state is to:

> Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of electric retail service and the development of performance standards and targets for service quality for all

consumers, including annual achievement reports written in plain language.

Even though the proposed ESSS rule changes would improve the process going forward, the OCC would still recommend a hearing. OCC bases its position on both the Companies' past performance in the area of service reliability and as a result of the recent service restoration issues across FirstEnergy's service territory in Ohio due to the windstorms caused by Hurricane Ike.

IV. FIRSTENERGY'S SERVICE QUALITY

Q20. DOES THE COMPANIES' ESP APPLICATION OR TESTIMONY ADDRESS ANY OF THE PROBLEMS RAISED IN THE DISTRIBUTION RATE CASE CONCERNING ITS SERVICE QUALITY?

A20. No. Neither the Companies' ESP Application nor testimony addresses these issues.

Q21. WHAT ARE THE COMPANIES' PROPOSALS IN ITS ESP APPLICATION WHICH DO ADDRESS THE COMPANIES' QUALITY OF SERVICE?

A21. Companies' witness Schneider's testimony addresses only the ESP proposals for: 1) the DSI Rider; 2) a SAIDI target adjustment and performance range; 3) a rear lot reduction factor for CEI's SAIDI; 4) a $1 billion five-year capital commitment; and, 5) a Smart Grid Study.

Q22. IN WHAT WAY DO THESE COMPANIES' PROPOSALS RELATE TO SERVICE RELIABILITY?

A22. By proposing a DSI rider and a five-year $1 billion capital commitment, the Companies seem to recognize the need to devote additional resources to reliability matters and to replace aging infrastructure. In their ESP, the Companies' propose that the reliability target for SAIDI be adjusted upward for CEI but remain unchanged for OE and TE. It should be noted here that an upward adjustment in SAIDI increases the duration time for an average outage and the target is therefore less stringent.

Also for CEI only, a rear lot reduction factor for calculating SAIDI is proposed. The Companies also propose a performance range for SAIDI which would be used to adjust the DSI Rider based on each Companies' actual annual SAIDI performance.

Q23. WHAT DOES THE COMPANIES' SAIDI TARGET REPRESENT?

A23. The term SAIDI stands for "System Average Interruption Duration Index." It is calculated by dividing the sum of all outage durations for a time period such as a year by the total number of customers served by the distribution system. The number is measured in either hours or minutes and represents the average outage duration per customer on the system. For example, a SAIDI of 120 minutes means that the average system customer can expect to be out of power for 120 minutes each year. If the target for SAIDI is increased, i.e. 150 minutes, it is less stringent while a decrease in the SAIDI target, i.e. 100 minutes, is more stringent.

V. THE DSI RIDER

A. FirstEnergy's Proposed DSI Rider

Q24. WHAT DOES FIRSTENERGY PROPOSE AS A DSI RIDER?

A24. As described by Mr. Schneider, the DSI Rider is a non-bypassable distribution charge equal, on average, to $0.0020 per kWh on a service rendered basis. He goes on to state that the Companies need the rider to ensure that they are in a position to devote appropriate resources to reliability matters.[5] Mr. Schneider reiterates this point by stating that a DSI Rider is needed to provide the Companies the financial wherewithal to remain healthy and capable of continuing their ongoing commitments to the energy delivery and customer service business.[6]

Q25. HOW DOES THE PROPOSED DSI RIDER WORK?

A25. The DSI Rider would be subject to an annual adjustment, either up or down, based on each individual Company's actual performance for the previous year. The DSI Rider would be adjusted whenever the actual performance falls outside of a predetermined "range of no change" for SAIDI performance. According to Section A.3.f of the Companies' ESP Application, the Companies' SAIDI targets shall be 120 minutes and the performance band or "range of no change" shall range from 90 minutes to 135 minutes. If the SAIDI performance for one of the Companies is higher than 135 minutes, then the DSI rider for that Company will be decreased consistent with the amounts in the proposed tariffs. If the SAIDI

[5] See FirstEnergy Witness Schneider Direct Testimony at page 5.

[6] Id. at page 4, lines 14-18.

performance is less than 90 minutes, then the DSI rider for that Company will be increased consistent with the amounts in the proposed tariffs. The annual adjustment either upward or downward as proposed shall not exceed 15% for any calendar year.

Q26. HOW DO THE COMPANIES PROPOSE TO LIMIT THE ADJUSTMENT OF THE DSI RIDER TO 15%?

A26. According to Section A.3.f of the Companies ESP Application, the annual adjustment, either upward or downward, will not exceed 15% of the average DSI Rider for all three Companies in the aggregate. However, the Application fails to explain how the 15% adjustment will continue to occur after the rider is set to zero in 2012 and 2013.

B. OCC's Analysis And Recommendation

Q27. WHAT IS OCC'S POSITION CONCERNING THE PROPOSED DSI RIDER?

A27. The Companies have provided no justification for the need of the DSI Rider. Unsupported statements in the Application and testimony are not adequate to properly analyze the Companies' request for the Rider. Consumers should not be required to pay for activities the Companies' may not undertake or which may not provide beneficial results.

Q28. DO THE COMPANIES HAVE SPECIFIC AREAS OF NEED FOR WHICH THE FUNDS FROM THE DSI RIDER WILL BE TARGETED?

A28. According to the Companies' ESP Application, at page 21, the DSI Rider will enable the Companies to manage the increasing costs of providing service, address the need to expend capital earlier, train new employees, replace aging infrastructure, and address the importance of reliability and the emergence of new technology such as the Smart Grid.

Q29. HAVE THE COMPANIES PRESENTED EVIDENCE THAT THE DSI RIDER IS NEEDED TO ENABLE THE COMPANIES TO MANAGE THE INCREASING COSTS OF PROVIDING SERVICE?

A29. No. The Companies, and especially Mr. Schneider, provide no analysis or details supporting the need for the DSI Rider. For example, the Companies do not identify which costs have increased nor do they identify the "price tag" for any of the above items.

Q30. IS THE COMPANIES' PROPOSED DSI RIDER FLAWED?

A30. Yes. Electric utility customers should not have to pay "extra" for an acceptable level of reliable service. As currently proposed, the Companies would collect additional revenue through the DSI rider whenever their SAIDI fell within a fairly large range of acceptable values.

Q31. SHOULD THE COMMISSION APPROVE THE PROPOSED DSI RIDER?

A31. No. CEI has only just begun implementing the improvements needed to meet its reliability targets (as recommended by UMS and Staff). Mr. Schneider reaffirms the capital spending commitment in the response to Staff data request 4 – 3 by stating ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** It is premature to judge the final impact that this level of capital spending will have on CEI's service reliability performance for at least another three years.

Q32. WHAT IS THE ANTICIPATED IMPACT ON FIRSTENERGY'S RELIABILITY PERFORMANCE IF THE DSI RIDER IS NOT APPROVED?

A32. According to the response to Staff data request 4-24, ***BEGIN CONFIDENTIAL***[redacted][7]***END CONFIDENTIAL***

Q33. IS THE CONCEPT OF TYING RATE ADJUSTMENTS TO A COMPANY'S SERVICE RELIABILITY COMMONLY ACCEPTED?

A33. No. I know of only one other jurisdiction which has this type of rate. Since 1986, Mississippi Power Company ("MPCo") has operated under a Performance Evaluation Plan Rate Schedule ("PEP-4"). Unlike the DSI rider, which is tied only to the utility's SAIDI performance, the PEP-4 rate is determined by three different factors which are designed to provide the most value to customers – low price, high service reliability, and high customer satisfaction. The tariff also

[7] See response to Staff data request 4 – 24 (Attachment DWC-2).

establishes a "range of no change" for each factor. Annually MPCo's rates may go up, go down, or remain unchanged depending on their performance. Since the PEP-4 rate is based on price as well as service reliability, MPCo is not only motivated to improve service reliability but is also incented to lower their price by achieving cost savings though innovation and operating efficiencies.

Q34. WOULD OCC BE OPPOSED TO THE CONCEPT OF REWARDING THE COMPANIES FOR EXEMPLIARY PERFORMANCE?

A34. OCC would be open to a discussion which considers such a concept.

C. Reliability Targets and the DSI Rider

Q35. WHAT ARE THE COMPANIES' RELIABILITY TARGETS AND WHAT HAS BEEN THEIR RELIABILITY PERFORMANCE OVER THE PAST SEVERAL YEARS?

A35. ***BEGIN CONFIDENTIAL*** [redacted][8] ***END CONFIDENTIAL***

[8] See response to OCC Interrogatory No. 27 (Attachment DWC-3)

Q36. IF THE COMISSION WERE TO ALLOW A DSI RIDER, DO YOU AGREE WITH THE USE OF SAIDI AS THE SINGLE RELIABILITY INDEX TO ADJUST THE DSI RIDER?

A36. First, any discussion of the use of SAIDI for adjusting the proposed DSI rider must be kept distinct and separate from the Companies' requirements to set performance targets for CAIDI and SAIFI and reporting their performance as required by the ESSS rules. Relative to the proposed DSI Rider, I would not be opposed to the use of only SAIDI for adjustment of the proposed rider. However, relative to the requirements of the ESSS rules, I believe both CAIDI and SAIFI continue to provide valuable and useful information and must be retained by the Commission as measures of the Companies' reliability performance. It is important for the Companies to report on both the duration *and* frequency of outages.

Q37. HOW DO EACH OF THE COMPANIES' CURRENT SAIDI PERFORMANCE TARGETS COMPARE TO THE TARGETS PROPOSED IN THE ESP?

A37. ***BEGIN CONFIDENTIAL*** [redacted] [9] [redacted].***END CONFIDENTIAL***

[9] See the response to OCC Interrogatory No. 27 (Attachment DWC-3).

Q38. HOW DOES THE COMPANIES' PAST SAIDI PERFORMANCE COMPARE TO THE PROPOSED 120 MINUTE TARGET IN THE DSI RIDER?

A38. ***BEGIN CONFIDENTIAL*** [redacted][10] ***END CONFIDENTIAL***

Q39. DURING THE PERIOD FROM 2000 – 2007, HAVE ANY OF THE COMPANIES' SAIDI PERFORMANCE GONE OVER THE UPPER LIMIT OF THE PROPOSED DSI RIDER SAIDI RANGE OF 135 MINUTES?

A39. ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL***

Q40. DURING THE PERIOD FROM 2000 – 2007, HAVE ANY OF THE COMPANIES' SAIDI PERFORMANCE GONE UNDER THE LOWER LIMIT OF THE PROPOSED DSI SAIDI RANGE OF 90 MINUTES?

[10] Id.

A40. ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL***

Q41. HAVE YOU PREPARED A TABLE SUMMARIZING THIS DATA?

A41. Yes. The table below provides a summary. ***BEGIN CONFIDENTIAL***

END CONFIDENTIAL

Q42. WHAT IS THE COMPANIES' JUSTIFICATION FOR ADJUSTING CEI'S SAIDI TARGET UPWARD FROM 95 TO 120 MINUTES?

A42. According to page 6 of Mr. Schneider's testimony, the 120 minutes represents the optimal reliability performance for CEI to balance service reliability and costs and on page 8 he states that it represents second quartile performance based on IEEE performance measures.

Q43. IS THE PROPOSED TARGET OF 120 MINUTES FOR SAIDI THE OPTIMAL RELIABILITY PERFORMANCE FOR CEI?

A43. I do not know since Mr. Schneider's testimony does not provide an explanation as to why 120 minutes provides the optimal balance between reliability performance and costs.

D. CEI's Rear Lot Reduction Factor

Q44. HAVE THE COMPANIES PROPOSED ANY OTHER ADJUSTMENTS TO THE SAIDI CALCULATION THEY WOULD USE FOR THE DSI RIDER?

A44. Yes, the Companies have proposed a Rear Lot Reduction Factor ("RLRF") for CEI only.

Q45. WHY IS FIRSTENERGY PROPOSING A REAR LOT REDUCTION FACTOR AND HOW WOULD IT WORK?

A45. The Companies contend that CEI's service area geography makes it extremely difficult to restore power quickly due to the large number of rear lot facilities. Mr. Schneider states that service restoration times are longer for these facilities because of obstructions located on the rear lots such as trees, fences, and garages.[11] The Companies also contend that this requires the utility to manually

[11] Schneider testimony at 7.

haul poles and equipment to such sites instead of using trucks. When calculating SAIDI for adjusting the proposed DSI rider, the Companies propose that a fifty percent reduction in the outage minutes for any of CEI's circuits where greater than one half of the customers are served by rear lot facilities be applied.

Q46. WHAT IS THE COMPANIES' BASIS FOR THE PROPOSED FIFTY PERCENT REDUCTION IN CUSTOMER OUTAGE MINUTES FOR CIRCUITS WITH A MAJORITY OF REAR LOT FACILITIES?

A46. In discovery the Companies state ***BEGIN CONFIDENTIAL*** [redacted][12] ***END CONFIDENTIAL***

Q47. WHAT IS YOUR EVALUATION OF THE COMPANIES' ANALYSIS?

A47. The Companies' analysis lacks the detail to properly evaluate the proposed 50% reduction factor. While restoration times may be shorter for front lot facilities due

[12] See response to Staff data request 4 - 32 (Attachment DWC-2).

to the use of bucket trucks, this certainly is not always true and is an oversimplification of the rear lot issue. For example, some of the rear lot construction may actually be underground facilities and therefore the need to manually haul poles to make repairs is not a factor. Also, some areas have alleyways, especially in older subdivisions and cities, located on the rear lot side which allows access for the Companies' trucks.

Furthermore, just as with rear lots, not all front lot facilities are accessible to trucks because the service poles needing repair are located on either side of the property. Also like rear lot construction, there are obstructions on the front side such as curbs, hydrants, parked vehicles, and fences which may impede the use of trucks. These situations will require line technicians to climb the poles at either location making the repair time the same.

In addition, the time differential between front lot and rear lot restoration is dependent upon the outage cause. For example, the time required for replacing a small piece of equipment such as a line fuse or a cutout on rear a lot circuit is not significantly greater than that required for a front lot circuit. The time differential may be greater, however, if large and/or heavy items such as poles and transformers are required for the repair job. Mr. Schneider states that these items must be manually hauled to the repair site. However, he does not consider the possibility of utilizing small portable hauling equipment such as an EZ Hauler pole trailer to haul heavy items to the rear lot site.

Q48. IF YOU AGREE THAT SOME REAR LOT REPAIR WORK MAY TAKE MORE TIME MORE TIME THAN FRONT LOT WORK, WHY DO YOU DISAGREE WITH THE NEED FOR THE RLRF?

A48. First of all, the Companies are proposing to increase CEI's SAIDI from 95 minutes to 120 minutes, a 26% increase, and the proposed DSI rider is not reduced until its SAIDI reaches 135 minutes. Thus, not only is CEI's SAIDI target changed (made easier to achieve), the outage minutes for many of its circuits will be reduced by 50% with the RLRF. In addition, the proposed change in the target and the application of the RLRF would also affect the Companies ESSS reporting and reliability requirements. This is not acceptable. I believe that this 26% increase in CEI's ESSS targets compensates for any problems associated with restoration times for rear lot construction. In addition, I believe that merely granting an adjustment to the SAIDI calculation does not incent the Companies to pursue real solutions to solve the problems associated with the restoration times required for rear lot construction. Rather, it may serve to mask or downplay a problem which needs to be addressed. In the end, it will not change the fact that CEI's customers on an RLRF circuit can actually be out of service for 240 minutes even though only 120 minutes will be reported by the Company.

Q49. HOW MANY OF CEI'S DISTRIBUTION CIRCUITS HAVE MORE THAN HALF OF THE CUSTOMERS SERVED BY REAR LOT FACILITIES?

A49. According to FirstEnergy's response to Staff data request 4-32, there are a total of ***BEGIN CONFIDENTIAL*** [redacted]

[redacted]***END CONFIDENTIAL***of those have a majority of the residential customers being served by rear lot construction.[13]

Q50. WHAT IS THE POTENTIAL EFFECT THAT THE RLRF COULD HAVE ON CEI'S SAIDI PERFORMANCE IF APPLIED TO HISTORICAL DATA?

A50. The SAIDI minutes for CEI with rear lot reduction factor applied to actual data for 2003 – 2007 would result in adjusted SAIDI values ranging between ***BEGIN CONFIDENTIAL*** [redacted][14] [redacted] ***END CONFIDENTIAL*** the Company would not experience a reduction in its proposed DSI rider.

Q51. IF THE RLRF WERE APPLIED TO CEI'S PAST SAIDI PERFORMANCE, HOW OFTEN WOULD CEI HAVE GONE OVER THE UPPER LIMIT OF THE PROPOSED DSI SAIDI RANGE OF 135 MINUTES?

A51. The SAIDI for CEI would have gone over ***BEGIN CONFIDENTIAL***[redacted][15] ***END CONFIDENTIAL***

[13] See response to Staff data request 4 – 32 (Attachment DWC-2).

[14] See the response to OCC Interrogatory 28 (see Attachment DWC-4).

[15] Id.

Q52. WHAT IS YOUR CONCLUSION CONCERNING THE COMPANIES' PROPOSED REAR LOT REDUCTION FACTOR?

A52. The Commission should reject the Companies' proposal for the RLRF. I believe that granting an adjustment to the SAIDI calculation does not provide the proper incentive to the Companies to pursue more proactive, innovative, and more cost effective solutions to the rear lot issue. Further, the proposed increase in the SAIDI target for CEI to 120 minutes will mitigate potential impact due to rear lot construction.

Q53. WHAT DO YOU MEAN BY MORE PROACTIVE AND INNOVATIVE APPROACHES TO SOLVE THE REAR LOT ISSUE?

A53. An example of a proactive approach would be for the Companies to intensify their existing inspection programs to identify potential problems with rear lot facilities, especially poles and transformers. Problems identified in this way could be repaired via planned outages during normal work hours, lowering the cost of labor and minimizing outage time and inconvenience to customers. An example of an innovative approach would include utilizing new technologies that can locate faulty equipment prior to failure (e.g. Exacter). Examples of industry best practices include enhanced vegetation management, replacing wood poles with lighter, easier to handle steel poles, and/or utilizing portable hauling equipment (e.g. EZ-Hauler) to haul heavy equipment such as poles and transformers to rear lot locations that are not accessible to trucks.

E. Capital Spending and the DSI Rider

Q54. IF THE DSI RIDER WERE NOT APPROVED BY THE COMMISSION IN THIS ESP CASE, WOULD THE FIRSTENERGY COMPANIES CHANGE HOW THEY DECIDE WHICH DISTRIBUTION CAPITAL PROJECTS TO IMPLEMENT?

A54. No. According to the Companies' answer to Staff data request 4-13, ***BEGIN CONFIDENTIAL*** [redacted][16] ***END CONFIDENTIAL***

Q55. WHAT IS THE RELATIONSHIP BETWEEN APPROVAL OF THE DSI RIDER AND CEI'S COMMITMENT IN CASE 07-551-EL-AIR TO MAINTAIN ITS CAPITAL SPENDING AT A MINIMUM LEVEL OF $84.7 MILLION FOR AT LEAST FIVE YEARS?

A55. According to the Companies, ***BEGIN CONFIDENTIAL*** [redacted]

[16] See response to Staff data request 4 – 13 (Attachment DWC-2).

[redacted][17] ***END CONFIDENTIAL***

Q56. WHAT IS THE RELATIONSHIP BETWEEN APPROVAL OF THE DSI RIDER AND THE COMPANIES' $1 BILLION CAPITAL COMMITMENT CONTAINED IN ITS ESP APPLICATION?

A56. The DSI Rider and the $1 billion capital commitment are separate items. According to Staff data request 4-13, the Company says that ***BEGIN CONFIDENTIAL***[redacted][18] ***END CONFIDENTIAL*** I will discuss the $1 billion capital commitment in more detail later in my testimony.

Q57. WHAT IS THE ANTICIPATED IMPACT ON EACH OF THE FIRSTENERGY COMPANY'S RELIABILITY PERFORMANCE IF THE DSI RIDER IS NOT APPROVED?

A57. According to Staff data request 4-24, ***BEGIN CONFIDENTIAL***[redacted] ***END CONFIDENTIAL***

[17] See response to Staff data request 4 – 3 (Attachment DWC-2)

[18] See response to Staff data request 4 – 13 (Attachment DWC-2)

Q58. WHAT IS THE ANTICIPATED IMPACT ON EACH OF THE FIRSTENERGY COMPANIES' O&M EXPENSES IF THE DSI RIDER IS NOT APPROVED?

A58. According to Staff data request 4-17, ***BEGIN CONFIDENTIAL***[redacted] ***END CONFIDENTIAL***

Q59. WHAT IS WRONG WITH THE FACT THAT THE COMPANIES HAVE DONE NO ANALYSES TO DETERMINE THE IMPACT THE DSI RIDER WILL HAVE ON THEIR RELIABILITY?

A59. The Companies appear not to have a clear-cut plan for the use of the revenues generated by the proposed DSI rider. Without such a plan, it is difficult to understand how the Companies can know what their cost will be, how much revenue that they will need to cover those costs, and how to prioritize their expenditures in order to maximize the use to of the funds. Without the identification of specific programs and projects with estimated costs and benefits, the rider does not have sufficient justification.

Q60. DO THE COMPANIES PROPOSE TO PROVIDE ASSURANCE THAT THE DSI RIDER REVENUES COLLECTED FROM CUSTOMERS ARE ACTUALLY SPENT ON THE PROJECTS AND EXPENSE CATAGORIES FOR WHICH THEY ARE INTENDED?

A60. No, the Companies have not committed to provide controls to make sure the rider revenues received from customers are spent on designated projects. According to Staff data request 4-21, ***BEGIN CONFIDENTIAL*** [redacted][19] ***END CONFIDENTIAL***

Q61. IN YOUR OPINION, WHAT WILL BE THE OVERALL AFFECT OF THE COMPANIES' PROPOSED ANNUAL ADJUSTMENTS TO THE DSI RIDER?

A61. I would expect that the net effect of the proposed annual adjustments will be zero in most instances. Based on the historical data the Companies supplied in response to OCC INT-27, OE's SAIDI already falls consistently ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL***and therefore would be expected to seldom receive either an increase or decrease to the OE DSI Rider. The same is true for TE except for an occasional ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** SAIDI performance and thus would receive an increase in their DSI rider. As I testified previously, I would expect the steady improvement in CEI's SAIDI to continue because of their recent commitment to capital spending and ***BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL*** performance in the near term. Due to CEI's increased

[19] See response to Staff data request 4 -21 (Attachment DWC-2)

capital spending coupled with the proposed wide range of values for acceptable SAIDI performance, I anticipate at a minimum the Companies will have as many "winners as losers" and thus in the aggregate the proposed adjustments will have little net effect.

Q62. WHAT IS OCC'S RECOMMENDATION CONCERNING THE COMPANIES' PROPOSED DSI RIDER?

A62. The OCC recommends that the Commission reject the Companies' proposal to implement the DSI Rider. As proposed in the Companies' ESP Application, the Rider has not been justified on the basis of cost or need, the design of the rider is flawed, and the timing is premature. The Companies have loosely tied the need for the rider to areas of general concern such as rising material costs, accelerated replacement of aging infrastructure, training of new employees, and requirements for a future Smart Grid. However, there are no specific programs or projects identified by the Companies, no cost/benefit analysis, and no discussion of potential costs savings that could serve to offset the costs associated with the identified areas of concern. Even if some of the Companies' concerns are legitimate, there are no specified amounts designated for each area of concern, no controls planned for the expenditures, and thus no guarantee that the funds will be spent on the intended projects. In summary, the proposed Rider is not justified and should be rejected.

VI. CAPITAL IMPROVEMENT PROGRAM

Q63. HOW DO THE COMPANIES INTEND TO IMPROVE THEIR RELIABILITY PERFORMANCE UNDER THE ESP?

A63. One of the major components of the FirstEnergy Companies' ESP Application in this area is their commitment to capital expenditures. According to Mr. Schneider, the Companies commit to make capital investments in their energy delivery system of at least $1 billion from 2009 – 2013. He contends this commitment helps to ensure that sufficient capital is being spent to address distribution system improvements.[20]

Q64. WILL THIS $1 BILLION CAPITAL EXPENDITURE COMMITMENT BE FUNDED THROUGH THE DSI RIDER?

A64. No, the Company has stated that the DSI Rider and the $1 billion capital commitment are separate items. According to their response to Staff's data request, the Companies say that ***BEGIN CONFIDENTIAL*** [redacted][21] ***END CONFIDENTIAL***

Q65. IS THE COMPANIES' FIVE-YEAR $1 BILLION CAPITAL PROGRAM IN ITS ESP A NEW COMMITMENT?

[20] Schneider Direct Testimony at page 10.

[21] See response to Staff data request 4 – 13 (Attachment DWC-2)

A65. Not entirely. The Companies had already made a partial commitment for CEI in the Distribution Rate Case. The Companies committed $84.7 million for five years or approximately $424 million of the $1 billion capital commitment.

Q66. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANIES' PROPOSED FIVE YEAR $1 BILLION CAPITAL COMMITMENT IN ITS ESP AND CEI'S COMMITMENT TO MAINTAIN ITS CAPITAL SPENDING AT A MINIMUM LEVEL OF $84.7 MILLION FOR AT LEAST FIVE YEARS?

A66. CEI's commitment to spend $84.7 million for five years is part of the record in the Distribution Rate Case and is based on the first long-term recommendation on page 32 of the UMS report. According to their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL*** [redacted][22] ***END CONFIDENTIAL***

Q67. WHAT IS THE RELATIONSHIP BETWEEN THE COMPANIES' PROPOSED FIVE YEAR $1 BILLION CAPITAL COMMITMENT IN ITS ESP AND THEIR TOTAL CAPITAL EXPENDITURES FOR THE PREVIOUS FIVE YEAR PERIOD?

[22] See response to Staff data request 4 – 3 (Attachment DWC-2)

A67. Based on their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL*** [redacted][23] ***END CONFIDENTIAL***

Q68. HAVE THE COMPANIES ESTIMATED THE IMPACT THAT THE $1 BILLION CAPITAL EXPENDITURE COMMITMENT WILL HAVE ON THEIR SAIFI AND CAIDI PERFORMANCE?

A68. No. According to their response to Staff's data request, the Companies state that ***BEGIN CONFIDENTIAL*** [redacted][24] ***END CONFIDENTIAL***

Q69. WHAT IS OCC'S RECOMMENDATION CONCERNING THE COMPANIES' COMMITMENT TO SPEND $1 BILLION ON CAPITAL IMPROVEMENTS OVER THE NEXT FIVE YEARS?

A69. The OCC believes that additional expenditures are and will continue to be needed to be reinvested in the Companies' distribution infrastructure. However, the total amount of capital expenditures needed to achieve and sustain achievement of reliability targets is an unknown quantity. OCC recommends that the

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[23] See response to Staff data request 4 – 6 (Attachment DWC 2)

[24] See response to Staff data request 4 – 22 (Attachment DWC-2)

Commission continue to monitor the Companies' capital expenditures to ascertain that the Companies are staying true to their commitments to focus spending on reliability needs.

VII. OCC RECOMMENDATIONS

Q70. IN SUMMARY, WHAT ARE OCC'S RECOMMENDATIONS RELATED TO PROTECTING AND IMPROVING SERVICE RELIABILILTY FOR CUSTOMERS?

A70. 1. The Commission should adopt all of OCC's recommendations from the Companies' Distribution Rate Case.

2. The Commission should reject the Companies' proposal to implement the Delivery Service Improvement Rider and the Rear Lot Reduction Factor.

3. The Commission should continue to monitor the Companies' capital expenditures to ascertain that the Companies are staying true to their commitments to focus spending on reliability needs.

Q71. DOES THIS CONCLUDE YOUR TESTIMONY?

A71. Yes. However, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event the PUCO Staff fails to support the recommendations made in the Staff Report and/or changes positions made in the Staff Report.

Final Report

2007 Focused Assessment
of the
Cleveland Electric Illuminating Company

Conducted by

UMS Group Inc.
5 Sylvan Way, Suite 120
Parsippany, NJ 07054

October 2007

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1.0 Executive Summary

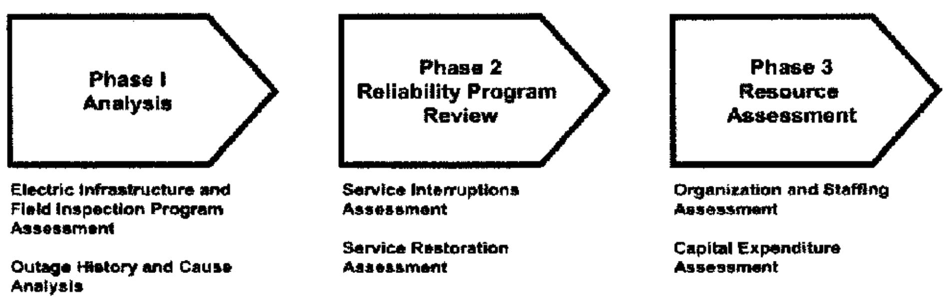
1.1 Introduction

In the Summer and Fall of 2007 UMS Group conducted a focused assessment of the practices, policies, and procedures of The Illuminating Company (hereinafter referred to as "CEI" or "the Company") relating to the Company's efforts to improve electrical system reliability in its distribution network during the 2002-2006 period. Our overarching objective was to identify specific reliability improvement opportunities to enable the Company to achieve its existing reliability targets by 2009 and to sustain this level of reliability performance over the following 10-year period.

In so doing, we examined the effectiveness of the Company's recently implemented procedures, initiatives, and technologies to improve overall reliability performance. Our approach to this work involved a three-phased diagnostic process to both identify and estimate the impact of potential improvements to the Company's current reliability programs.

Figure 1-1 below characterizes the nature of our three-phased assessment approach.

Figure 1-1
UMS Group's 3-Phased Diagnostic Process



Phase 1: Infrastructure and Outage History and Cause Analyses

During this initial phase, UMS Group conducted a selected sampling across CEI's 2 substation areas and 9 distribution line districts to verify the accuracy of CEI's system condition records, visually assess the physical condition of a sample of the system assets, and determine the effectiveness of and adherence to the Company's established Field Inspection policies and practices. The details of this analysis are presented in Section 2.0 of this report.

Based on the findings of this inspection effort, we then analyzed a 5-year history (2002-2006) of outage events at both the company and district level to determine the major drivers of system reliability performance and to identify targeted opportunities for cost-effective reliability improvement. From this analysis we developed insights and conclusions to (1) validate many of the ongoing practices and (2) develop recommendations to not only reach the 2009 reliability performance targets but to sustain that level of performance for 10 years. Section 3.0 of this report highlights the detailed results of the outage analysis.

Phase 2: Reliability Program Review

Building on the findings of Phase 1 of our analysis, we conducted over 29 technical interviews to assess: (1) CEI programs and approaches to eliminate and/or remediate customer interruptions (measured by SAIFI); and (2) the processes and practices employed in reducing customer minutes of interruptions (measured by CAIDI). A number of recommendations were developed, providing a roadmap for sustainable improvement in SAIFI and CAIDI. This effort also included the analysis of over 69 major data requests presented to the Company. Section 4.0 of this report highlights the Reliability Framework we used to structure our analysis. Section 5.0 of this report describes the Company's performance and improvement opportunities related to service interruptions; Section 6.0 of this report highlights the Company's performance and improvement opportunities related to service restoration.

Phase 3: Resource Assessment

The third phase of this assessment acknowledges that the recommendations developed during the Reliability Program Review will require resources in the form of skilled staff, effective organization, and adequate funding to be properly implemented. Section 7.0 of this report provides a detailed review of the Company's organization and staffing levels as they relate to system reliability and Section 8.0 explains our analysis of the Company's capital expenditure process.

During this phase, UMS Group developed a rationale and strategy to better identify the proper funding and staffing levels necessary to support our recommendations and achieve the targets specified in the 2005 ESSS Rule 10 Action Plan.

As part of this three-phased effort, UMS Group also independently reviewed CEI's performance against the 2005 ESSS Rule 10 Action Plan for compliance and to assess its impact on the Company's ability to realize the reliability targets as specified by the Public Utility Commission of Ohio (hereinafter referred to as "PUCO", with its supporting staff referred to as "the Staff"). The findings of this analysis are contained throughout this report and they are also expressly summarized in Section 9.0 of this report

The following sections of this Executive Summary present a synopsis of our major observations, recommendations, and conclusions related to this assessment. The detailed results of our assessment are presented in the corresponding report sections in the remainder of this report. The more significant reliability-related improvement opportunities identified in this report are also highlighted and evaluated at the end of this Executive Summary section. In this context, we present (where applicable) an estimated cost and anticipated reliability impact of these recommendations to overall system reliability performance.

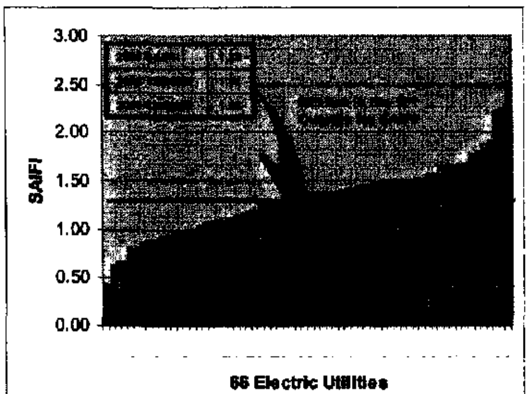
1.2 General Overview

As a result of this assessment, UMS Group has concluded that CEI is committed to improving overall electric system reliability. The Company's recent efforts have not only been designed and implemented to meet the specific provisions of the 2005 ESSS Rule 10 Action Plan (a detailed analysis of the Company's compliance is presented in Section 9.0). More importantly, we believe that the evidence outlined in this report supports the conclusion that the Company and its management team have been making *measurable* improvements related to system reliability in many aspects of its operation of, maintenance of, and investment in the CEI distribution system.

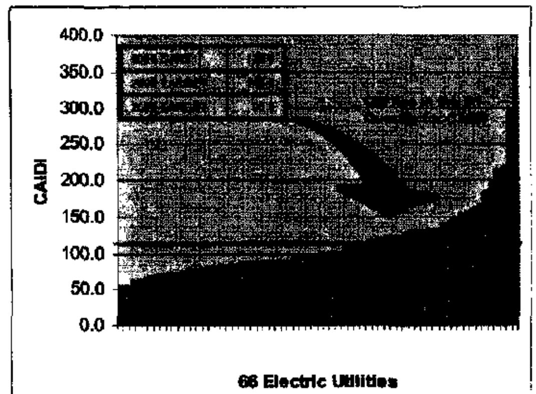
Although the results of this assessment are not uniformly positive in terms of performance or outcome, we believe that the evidence presented in this report shows that the Company has made and is continuing to make the necessary improvements in its procedures, processes, practices, spending levels and patterns, and investment planning that are necessary to improve system reliability and to ultimately meet the agreed upon reliability targets.

This assessment defines the actions (and their rationale) necessary for the Company to meet the targeted levels of reliability performance (specifically, SAIFI of 1.0 and CAIDI of 95.0) by 2009. From an industry-wide perspective, the challenge confronting the Company is that of striving to meet "top-quartile" performance in SAIFI and "second quartile" performance in CAIDI. Figure 1-2 below characterizes the Company's targets in the context of general industry patterns.

Figure 1-2
Industry Context for CEI's SAIFI and CAIDI Targets



Quartile	1st	2nd	3rd	4th
SAIFI	<1.05	1.06-1.38	1.39-1.53	>1.53



Quartile	1st	2nd	3rd	4th
CAIDI	<83.1	83.2-98.7	98.8-131.1	>131.1

The Company is committed to these existing targets and it understands and acknowledges this context and the scope of its challenge. The solution requires a programmatic, longer term strategy than can be realized between now and 2009. FirstEnergy's recently inaugurated Asset Management initiative has the potential to provide this solution by establishing a focus on maintaining and operating critical equipment (and associated components/sub-components) and ensuring tighter correlation between capital spending and system reliability through a well-planned and integrated prioritization process.

Significant financial and human resource commitments have already been made by FirstEnergy to this initiative. A detailed description of this initiative is presented Section 8.0 of this report and we note that it offers the Company its greatest opportunity and yet also its largest risk in terms of meeting the long range objective of sustained system reliability improvement over a 10-year period.

We believe that the Company's plans as they are currently conceived contain many of the key elements necessary to deliver the desired and expected reliability improvement. Our recommendations as outlined in this report in many cases accentuate or "fine-tune" existing practices or plans rather than identify previously unexposed opportunities. However, given the current material condition of the system (outlined in Section 2.0 of this report), we believe that the Company's ability to reach (or miss) these goals by 2009 will likely be more of a function of favorable (or unexpected) conditions (e.g. weather patterns, location of specific outages) than confirmation that the plans have reached their full potential.

Moreover, as is often the case when embarking on reliability improvement programs, there may even be a temporary reduction in *measured* reliability performance as the customer interruptions are *reduced just enough* to include storms that would have otherwise (under a less stable system) been excluded. Of course, over time the effect of a well-planned and executed plan will produce the sustainable results called for in the 2005 ESSS Rule 10 Action Plan.

With respect to the targets themselves, as Figure 1-2 illustrates, they are appropriately aggressive in that top-quartile SAIFI performance and second quartile CAIDI performance are by no means unreasonable goals to establish, particularly over the long run. Our belief is that in the case of the CEI they would represent outstanding performance (for the reasons specified above), particularly when compared with the targets established for the other Ohio utilities and similar systems (in terms of overhead/underground mix, age, condition, etc.)

During the period this report was being prepared, we also note that we became aware of PUCO Staff analysis of potential pending rule changes to what constitutes an excludable event. The storm exclusion threshold may be increased from 6 percent of total customers to 10 percent of total customers, all outages less than 5 minutes (currently at one minute) may be excluded, and planned outages (previously excluded) may be included. Using 2006 as a baseline (strictly for comparative purposes), the net impact of these potential changes would have increased the Company's SAIFI performance by 0.1 and CAIDI performance by 45 minutes.

The major contributor to these differences is adjusting the storm exclusion threshold to 10 percent of total customers (the approximate range for the 2.5 beta standard). Obviously, a more comprehensive analysis is called for (perhaps a 3-year average impact assessment); but, a dialogue around normalizing targets (or perhaps applying the new targets to smaller geographic areas) seems appropriate.

The discussion above regarding existing performance targets and potential measurement changes (that would potentially alter the nominal target for comparability) notwithstanding, the remainder of this report will focus on the targets as specified in the 2005 ESSS Rule 10 Action Plan and the ability of the Company to sustain that performance for 10 years.

Overall, the Company's reliability performance as presented in Figure 1-3 has improved in terms of service restoration (stepped improvement in CAIDI between the 2002/2003 time frame and the past 3 years), but with respect to service interruptions has not returned to 2002 level. Moreover, the performance from year to year has oscillated.

Figure 1-3
CEI 5-Year Reliability Performance

Measure	Units	2002	2003	2004	2005	2006
SAIDI	Minutes	147.21	205.10	149.69	193.25	150.44
SAIFI	Interrupts	0.95	1.22	1.14	1.69	1.17
CAIDI	Minutes	154.42	167.67	131.56	114.20	128.29

Special Note – The data shown in Figure 1-2 above originates from an updated database and does not precisely match the information reported to PUCO. The variance between this presentation and prior report is approximately 1 minute for CAIDI/SAIDI and less than 0.1 for SAIFI.

This lack of stability of performance suggested a need for thorough review of the Company's elimination and mitigation strategies for customer interruptions and a review and fine-tuning of the Company's practices currently instituted to reduce the duration of these interruptions

As we reviewed the Company's practices and processes around these performance measures and compared them with those of top quartile performers, we identified few actions that were not already in some form of implementation within the Company. However, as the following report will show, we believe that by disaggregating the outage data we were able to identify some key leverage points to assist the Company in maximizing the impact of these programs in the short term and identified longer term initiatives to fulfill the 10-year commitment of sustained reliable performance.

1.3 Reliability Analysis (Focused on 2009 Performance Targets)

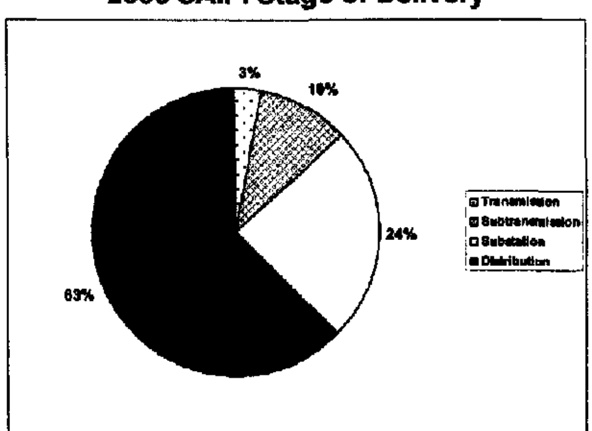
In establishing focus and direction to this analysis, we narrowed our view to "Non-Storm" events As a point of clarification, "Non-Storm" is synonymous with "Non-Major-Storm"; that is, while 'non-storm' excludes major storms that affect more than six percent of the Company's customers for a sustained 12-hour period, 'non-storm' includes the impact of minor storms, and is, in fact, driven at the margin by the frequency and severity of such minor storms and by the system's ability to minimize the interruptions and the outage durations experienced by customers in such minor storms. With that established we then disaggregated our analysis to better target areas that would provide the best leverage in improving reliability, initially focused on reducing service interruptions.

1.3.1 Reduce Customer Interruptions

Stage of Delivery

We initially looked at contributors to SAIFI (Figure 1-4) by Stage of Delivery (Transmission, Subtransmission, Substation and Distribution), where Distribution refers to the feeders. Obviously, the greatest opportunity for improvement is in the feeders (over 60 percent of the customer interruptions are attributed to feeders). That is not to say that improvement is not warranted in the areas of Subtransmission and Substations. But, the number of customer interruptions in these stages of delivery has been reduced, and the measures already taken should be sufficient to provide continued improvement.

Figure 1-4
2006 SAIFI Stage of Delivery



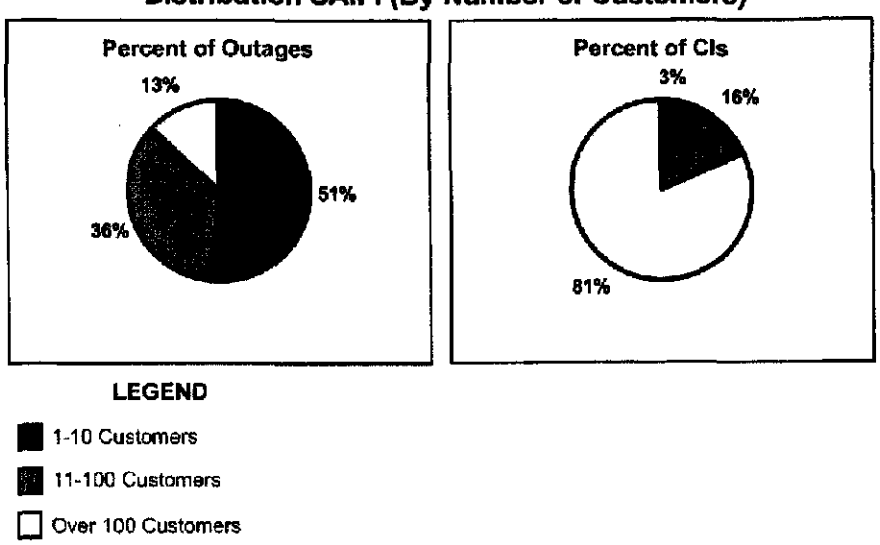
In reviewing the implications of the Stage of Delivery analysis (Figure 1-4), the following key points are summarized:

- The primary focus on this assessment should be on Distribution (it contributes 0.76 to SAIFI or 63 percent of the customer interruptions)
- Substation SAIFI, contributing 0.29 to SAIFI or 24 percent of the customer interruptions, requires parallel focus. However, the Feeder Breaker and Relay replacements and Animal Protection already being implemented across CEI should be sufficient to maintain steady improvement.
- Subtransmission SAIFI (contributing 0.12 to SAIFI or 10 percent of the customer interruptions) improved significantly between 2005 and 2006 (a 72.4 percent reduction in customer interruptions due to improved operability of the switches on the subtransmission system).
- Transmission SAIFI is negligible (not covered in this assessment).

Distribution SAIFI by Number of Customers Served

Within distribution (feeders), we then reviewed the distribution outages across the number of customers served. Figure 1-5 below illustrates that a relatively small percentage of outages (13 percent) had an appreciative effect on the numbers that drive SAIFI (customer interruptions). Therefore, any strategies and tactics aimed at reducing customer interruptions need to reflect the fact that 87 percent of the distribution outages accounted for only 19 percent of the customer interruptions (this is also indicative of effective fusing previously implemented by the Company).

Figure 1-5
Distribution SAIFI (By Number of Customers)



Distribution SAIFI by Cause Code

We then segmented the analyses from a number of different perspectives (e.g. voltage class, feeder breaker lockouts, geography), but in terms of identifying additional leverage points for development of strategies and actions, the SAIFI by Cause Code view provided the best insights. Over a five year period, 3 cause categories (Line Failure including lightning and wind-caused outages, Equipment Failure, and Trees/Non-Preventable) offer the Company its best opportunities (i.e. 89 percent of feeder-related SAIFI fell into these categories).

Figure 1-6 below presents this causal analysis by year.

Figure 1-6
Key Causes of Distribution SAIFI

Failure Cause	2002	2003	2004	2005	2006
Line Failure	0,12	0.22	0.21	0.25	0.26
Equipment Failure	0.10	0.10	0.11	0.14	0.24
Trees/Non-Preventable	0.09	0.09	0.11	0.11	0.13
TOTAL	**0.31**	**0.31**	**0.43**	**0.50**	**0.63**
PCNT D-SAIFI	**83%**	**87%**	**87%**	**84%**	**89%**

Key Strategies and Actions

Integrating the information derived from these four views, a two-tiered strategy was developed to ensure the Company maximizes its overall system reliability performance (as measured by SAIFI and CAIDI), yet maintains its focus on *customer* satisfaction. This strategy was composed of the following elements:

- **Protect the Backbone:** The cornerstone of this strategy is a focus on the feeder backbone. The backbone is the normally three-phase part of the circuit that runs unfused from the substation to the *normally open* ties to other circuits or to the physical end of the circuit (i.e. at a geographical or territory boundary, etc.). The backbone may include reclosers, but not fused taps. The associated actions are designed to either eliminate or mitigate customer interruptions:

  Vegetation Management (Eliminate Customer Interruptions)

  CEI's four-year tree trimming cycle under the FirstEnergy Vegetation Management Specification has been effective in reducing customer interruptions attributable to the category "tree-preventable", as evidenced by a reduction of contribution to SAIFI of .01 in 2003 to .001 in 2006 (ninety-nine percent of the tree-caused outages were characterized as non-preventable). UMS Group recommends that CEI extend the program to target "Priority" trees (in addition to the current "Danger" Tree program), i.e. – those that are most likely to cause outages to the backbone caused by broken limb/fallen tree situations

  This program would not be focused on merely avoiding grow-in contact-caused outages (although that effort must continue) but also on avoiding the most customer-impacting cases of broken limb and fallen tree by doing more to remove overhanging limbs and structurally weak trees. This approach cannot normally be cost-effectively applied to the entire system. The kind of clearances required would often be deemed excessive on the taps that typically serve two-lane suburban streets. However, feeder backbones typically are adjacent to major thoroughfares and commercial areas where enhanced removal is often more acceptable, particularly on the second or third time as the tree begins to take on the appearance of one that has 'grown away from the lines'.

  Lightning Protection (Eliminate Customer Interruptions)

  While deploying lightning arresters is the standard remedy (and usually a good one), there are other considerations that should be factored. These include: grounding, type of construction, and structures that support both transmission and distribution lines. CEI should also more effectively integrate the Insights available via the National Lightning Detection Network and the software program FALLS (Fault Analysis and Lightning Location System) to identify opportunities to more effectively protect the feeder backbone from lightning. Note that successful implementation requires that a lightning analysis be conducted before any protection solution is implemented.

Repair Pole and Pole-Top Fault Causing Equipment Problems (Eliminate Customer Interruptions)

UMS Group recommends that the current ESSS Inspection Program be integrated with this notion that a more select focus on the feeder backbone will provide the highest value in terms of inspection and follow-up on any noted deficiencies/exceptions. That is not to say that the inspections outside of the feeder backbone will be eliminated, but it does speak to frequency of inspections, and a more reliability-centered process of prioritization with varying follow-up time frame requirements.

Animal Mitigation (Eliminate Customer Interruptions)

CEI has integrated its Animal Guarding Program with its Line Inspection Programs and Substations utilizing planned and forced outages to apply the material already in stock. We have no additional recommendations to provide the Company in this area.

Feeder Sectionalizing (Mitigate Customer Interruptions)

In reviewing the over 1,000 4kV and 13.2kV circuits within the CEI system, 825 circuits do not have reclosers installed. Over 350 of these circuits serve more than 500 customers (considered by CEI as the optimum cut-off point for considering the installation of reclosers). Figure 1-7 provides a tabulation of these circuits by number of customers and voltage class:

Figure 1-7
CEI Circuits without Reclosers

Number of Customers	4kV Circuits	13.2kV Circuits	TOTAL
>2,000	0	24	24
1000-1999	37	64	101
750-999	80	16	96
500-749	113	19	132
TOTAL	**230**	**123**	**353**

Notwithstanding that many of these circuits may have experienced few, if any, backbone outages and some could be underground, this figure does suggest an opportunity to further sectionalize the feeder backbone and reduce the number of customer interruptions.

Another item to consider is the replacement of existing three-phase reclosers with single-phase reclosers (as well as using banks of single-phase reclosers for new recloser installations). Like many of our recommendations, this option should be considered on a circuit-by-circuit basis. Clearly, the advantage of reducing the number of interruptions by two-thirds is attractive. However, depending on the needs of the customer on that circuit, the impact to a major commercial or industrial customer that requires all three phases needs to be weighed against this benefit to other customers on the circuit.

Relaying/Over-Current Protection (Mitigate Customer Interruptions)

The primary operating issue with respect to relaying involves the decision to use the instant trip and timed re-close feature on reclosers. Our general recommendation with respect to this issue is that it is a decision that should be made on a circuit by circuit basis (i.e. not as a blanket policy across the entire system), considering the nature of the circuit and its customers, the history of success with instant trip and timed re-close on that circuit, and the damage that might be done to equipment if the instant trip is not set.

4kV Considerations (Eliminate Customer Interruptions)

Generally speaking, because of the relatively short runs of circuits associated with the 4kV system, sectionalizing provides little (if any) potential to improve reliability. However, since the 4kV feeders are more numerous, their exits from the substation often need to be underground, perhaps going a quarter-mile or more underground before reaching an overhead riser. As a result, cable failures on the exit cable, which would necessarily cause a lockout of the entire feeder, can be a common problem and one that will get worse as the very old cable in the similarly old conduits begins to reach the end of its useful life. We recommend that CEI continue its program of inspecting, maintaining, and even testing such cable in its attempt to prevent outages of this type.

- **Respond to Non-Backbone Multiple Customer Interruptions:** Sole focus on protecting the feeder backbone will inevitably lead to problems with respect to customer satisfaction. Whether a customer happens to be served by the backbone or off a tap brings no solace when confronted with an interruption in service. To address this, we suggest establishing a threshold criteria in terms of repeat interruptions (a pre-specified number of interruptions within a specified time frame) to initiate a proactive response. Obviously, all customers will get their service restored. The issue is when and to what extent a more comprehensive solution will be put in place that will prevent future outages. The following programs are natural candidates for this type of approach:

  Worst Performing Devices

  While it may not be cost-effective to try to avoid every outage on every device (especially when there is no obvious pattern that would lead one to target a class of devices as being most likely to fail), a program that focuses on repeat-offending devices is likely to be cost effective because it targets those few devices that have demonstrated a tendency to fail repetitively. Indeed, since each outage requires the utility to deploy resources to respond, if some effort can be made to fix the problem the first time (or with a single follow-up visit) the cost of the remediation may well pay for itself in short order through avoiding future restoration trips (to say nothing of the cost of dealing with customer complaints.). A criterion along the lines of reviewing all devices with 2 failures in a month (or 3 within a quarter) would seem appropriate.

URD Cable Replacement

The main reason that utilities are replacing failure-prone URD cable is to avoid customer complaints from repetitive failures and also to save repair costs. Once a cable starts to fail, the time between failures begins to accelerate. It is worth noting that the impact on SAIFI and CAIDI of a utility's entire URD replacement program, which may run from hundreds of thousands of dollars to even many millions of dollars for some utilities, is usually not very significant. This is because URD cable runs tend to involve only 10 to 50 customers, so each outage is a small one. As such, even if a utility were to experience a few hundred URD cable failures per year, it would cause less than 10,000 customer interruptions for an impact of about .02 on SAIFI for a utility with 750,000 customers like CEI. For this reason, we recommend that CEI sustain it's policy of replacement of URD cable after three failures on the same section.

1.3.2 Reduce Outage Duration

As previously stated, CEI has made a stepped improvement in CAIDI since the 2002/2003 period, closing the gap to the 2009 target by 50 percent (to approximately 128.0 minutes). This amount of improvement is indicative of an "all hands" effort, and speaks well to the teamwork and cooperation that has characterized the interactions across the various departments. That being said, the challenge to improve CAIDI by an additional 30-35 minutes is formidable, and will require continual fine-tuning of many of the practices already in place. Our analysis resulted in the following insights and conclusions:

Staff Mobilization

- With the exception of the Ashtabula line district, one of the more rural areas in the system, the overall trend in CAIDI performance from 2002 to 2006 is positive. Ashtabula represents almost half of the territory. The Company is in the process of establishing another line district (Claridon Township) (planned in-service date of 2009) to help alleviate the challenges inherent to such a large area. Combined with the new line district in Euclid in 2007, the Company is taking significant measures to improve *initial response time*.
- Pre-mobilization with respect to storms offers a potentially high leverage opportunity in eliminating customer minutes of interruption. By integrating all of the weather-related factors (e.g. effective wind speed, heat storms, lightning) into a common methodology, the Company can develop an empirical basis to augment the intuitive and experiential approach already being used to mobilize staff (in anticipation of a storm).
- Other staff mobilization-related practices (First Responder, Call-out, and Alternate Shift) appear to operating effectively; the most dramatic being the impact that the alternate shift has had on average outage duration during the 3:00 PM to 8:00 PM time frame (it is virtually indistinguishable from other time periods).

Work Flow

- The concept of applying partial restoration ("cut and run") appears to be a normal practice across the Company, and should definitely be continued. This is especially true on feeder backbones and large taps, even when that may involve 'cutting' perfectly good conductor in order to isolate faulted spans, so that crews can then 'run' to restore the remaining parts of the circuit.

- The Company has used the split and hit method on underground cable effectively for years; this is an industry leading practice and we recommend its continued use.

Communication

- The Company effectively employs all industry accepted norms in keeping all parties informed about the current state of restoration efforts and establishing a culture of continuous improvement through forums geared to constructive sharing of experiences and circumstances, both positive and negative.

1.4 Long Term Assessment (10-Year Vision)

The Company's long-term success depends on the Company's implementation of FirstEnergy's Asset Management-based Business Model. The Company is in the process of developing a strategy that integrates the refurbishment (and even replacement) of an aging electric infrastructure and revitalization of the Company's staff with a sound capital spending prioritization process. We believe this is foundational to the Company achieving sustained (i.e. 10 year) 1st or 2nd-quartile performance in reliability (as measured by SAIFI and CAIDI) and for that matter may be a critical success factor in realizing the 2009 performance targets.

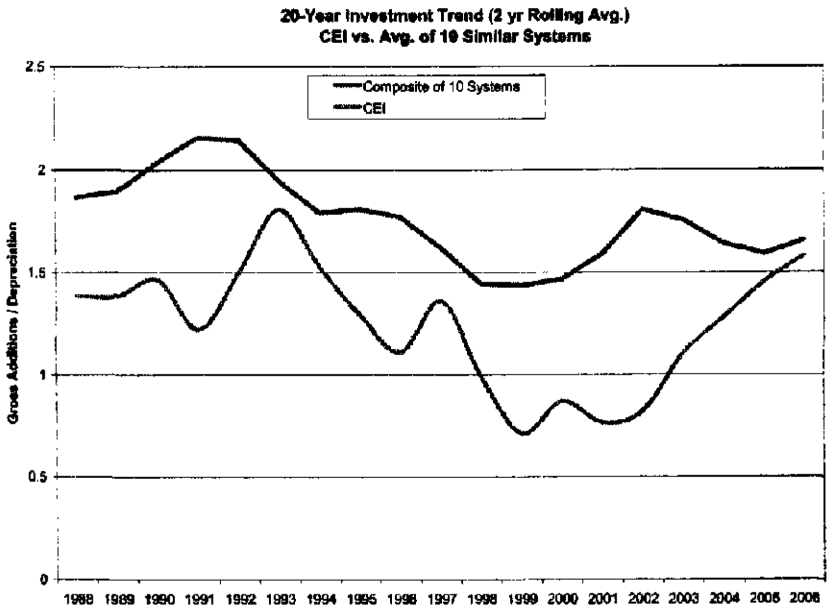
The key driver to realizing this vision is the amount of capital to be invested in the assets and then to properly allocate the capital in a manner that will yield the highest return in terms of improved performance. Therefore, the following discussion will first highlight the key points arrived at during the assessment of the Company's Capital Expenditures process and then address the issues of a deteriorating electric infrastructure and aging workforce.

1.4.1 Capital Expenditures

Level of Spending

Figure 1-8 presents a nearly 20-year trend of the ratio of *Gross Distribution Plant Additions / Depreciation* for CEI and for a composite of 10 U.S. electric utilities. The utilities in our reference composite measure were selected from similarly sized, Eastern U.S., urban/suburban systems. As discussed in Section 8.0, we selected this ratio as the most appropriate way to make relative comparisons of capital expenditures because it provides a practical and generally stable *relative* measure of investment levels among systems; moreover, it offers an indicator (albeit imprecise) of "reinvestment" in the system. To "dampen" the effect of extraordinary single year events (e.g. an extraordinary event or year), we prepared this data in a 2-year rolling average approach:

Figure 1-8
CEI Capital Spending vs. Similar Systems (1988-2006)



The implications of this comparative analysis are as follows:

- The Company's capital spending pattern over time has been consistent with the industry trends, albeit always at a *lower than average* level of spending for *all* years of this review.
- The Company has exhibited a strong investment pattern since 2003 and one that is counter *to general industry trends (i.e. CEI's investment has been increasing* when the industry is relatively flat). This suggests that the Company has recently sought to return to a more "normal' level of investment. In fact, the Company's 2006 capital expenditures were $69.1 million, an amount $8.1 million greater than the amount originally budgeted; and a similar pattern occurred in 2005, when CEI's actual capital expenditure was $47 5 million or $11.7 million greater than originally budgeted. Thus, we can find no evidence that FirstEnergy is "starving" the CEI system in recent years – further confirming the conclusion that the CEI system is clearly an investment priority within FirstEnergy system of companies.
- The Company's current capital plans also suggest that this elevated level of capital investment will continue in 2008 and beyond. Further, current (relatively higher) capital expenditure levels are scheduled to be sustained over the next few years.
- At an aggregate level, the CEI electric system may require some increased investment in the coming years to "catch up" on deferred capital replacement that has likely occurred in the past 20 years.

So, from a forward-looking perspective, the Company appears to be at the "right" level of capital spending.

Commitment to Reliability

We then analyzed the capital spending from a reliability perspective, both from a priority (vs. other capital commitments) and commitment (level of funding) perspective. This review resulted in the following observations:

- Overall "reliability-related" investment in 2006 was substantial, accounting for at least one-third of the capital spending during that year. In our experience, this is a strong investment pattern when compared to other, similar systems.
- "Reliability-related" spending in 2006 was at least $8.9 million greater than originally planned. When considered in the context of the $8.1million in additional (unbudgeted) capital spending in 2006, it is clear that reliability-related investment was one of the company's highest priorities in 2006.

Thus, we conclude that the company has made a strong recent commitment to reliability-related spending in 2006 and shows evidence of similar investment patterns in 2007.

Capital Planning and Improvement Process

The assessment next shifted to evaluating CEI's capital planning processes (including Project Prioritization) to verify the extent to which they begin with a clear identification and expression of system needs or issues (expansion commitments, reliability problems, etc.), are evaluated with a systematic and risk-considered approach that is designed to achieve optimal results given reasonable constraints (seasonal scheduling, availability of specialty tools or crews, etc.), and are automated to achieve systematic and reproducible results where appropriate. In so doing, we developed the following insights:

- CEI's processes during the past few years have exhibited many of the attributes that constitute a sound planning and prioritization process. They are holistic and need-/issue-driven. The Company and FirstEnergy overall have made efforts to standardize key elements in the issue identification, project classification, and risk definition steps. Such standardization allows for automation, record keeping, and consistency of decisions.
- CEI's risk assessment scoring process could be currently described as adequate and consistent with industry standards and practices. It has a strong, reliability-focused *Impact* measurement structure. However, the risk assessment could be significantly enhanced by adding a probabilistic (rather than a substantially qualitative) estimate of the *Likelihood* measurement dimension. This is a recently added element in the planning process and should improve its overall effectiveness.
- Implementing industry best practices would lead CEI to develop integrated systems that link the investment evaluation process and subsequent prioritization and funding to overall strategy (i.e. the investments contribution to meeting strategic objectives tied to system reliability, financial return on investment, etc.) and risk mitigation. In applying an approach that disaggregates the investment decision from resource utilization considerations, CEI will make significant strides in the area of Asset Management.
- One noteworthy element of this Asset Management initiative that relates to these capital-related processes is CEI's implementation of a Capital Prioritization

process (this project was inaugurated during the 2nd quarter 2007 just as this assessment was initiated). The approach and toolset (one of several available in the marketplace) has been developed over multiple years with numerous other large, investor-owned electric utilities. Consequently, it is a proven approach, embodies many of the industry's leading practices, and should expedite the Company's development in these areas.

Capital Processes Integrity

Our assessment of the integrity of CEI's capital-related business processes focused on whether these processes have been implemented as designed. From our interviews and a review of CEI's records related to the Company's capital planning and prioritization processes, it is apparent that the processes as described by company's management and technical team are being implemented as intended. These processes have high visibility and a large number of participants in all of the varying process stages defined above. There is an appropriate documentary trail to support that its conclusions and actions are implemented as planned.

At the present time the Company lacks a rigorous data relationship capability between the RPA database (a Lotus Notes application) and the SAP system (which tracks actual project activity). Although such conditions are less than ideal, they are also not uncommon given the complexity of maintaining interfaces between enterprise-based transaction systems (such as SAP) and active, Company-developed planning tools (such as the RPA system). Consequently, it is not possible to easily track and report "end-to-end" the performance of all RPAs through construction and completion (or deferral) in an automated way. Ideally, our analysis would have included an assessment to test whether the capital plans as approved from the RPA database were implemented (wholly or partially) as they are planned in SAP (i.e. – did "approved" projects actually get built and on what schedule?) Similarly, we also would have checked the process "in reverse", to determine that all projects that were constructed do indeed tie rigorously to an RPA (or not). At the present time such an assessment is not available in an automated way.

1.4.2 Refurbishment and Replacement of Aging Infrastructure

In assessing the Company's electric distribution infrastructure, 4 substations and 15 circuits (4kV, 13.2kV and 34.5kV) were inspected with a strong bias towards worst performing circuits and substations with a recent history of equipment problems. Other than to acknowledge the age of the equipment in the substations, the more significant programmatic-related insights originated from the circuit inspections:

- The CEI inspection records were adjudged adequate in their representation of the material condition of the system. However, there were 132 exceptions noted by UMS Group (on circuits previously inspected by CEI), that were not noted in the circuit inspection records.
- 128 of the 320 open exceptions were categorized as reliability-related (i.e. vegetation, broken cross arms, severely damaged pole or damaged lightning arrester). Of those, 41 could cause customer interruptions at any time. However, the reliability concern has less to do with these specific exceptions, and more to do with the accumulated effect of an accumulating *list of exceptions* and the compounding impact they might have on the overall material condition of the system.

- The overall condition of CEI's electric distribution system presents a significant challenge to CEI reaching top quartile performance in SAIFI and second quartile performance in CAIDI (i.e. the industry context for CEI's current reliability targets), particularly given the mandate to sustain this performance over a ten year period. The underlying causes include:

  ⇒ Inadequate funding for over a decade (commencing in the early-1990s), a phenomenon that was common across the industry. Every indication is that this shortfall is being addressed, but that the impact of a return to adequate spending levels will not be realized immediately.

  ⇒ Steadily decreasing staffing levels during this same time period amidst an increasingly challenging maintenance workload (due to increased inspection activities leading to higher levels of corrective maintenance and the inherent issues of aging equipment).

NOTE: The aforementioned insights should in no way be interpreted to lessen the importance of complying with the mandated ESSS Inspection Requirements (Rule 26) as 100 percent compliance should be the standard. It merely acknowledges the findings within the context of scope (the 15 selected circuits represented 347 miles of overhead lines/circuits and over 10,000 poles) and near term impact on system reliability (the current analysis reveals little, if any, correlation between the material condition of the assets and reliability as measured by SAIFI and CAIDI).

Recognizing a problem that has been 10-15 years in the making cannot be reversed overnight, the solution involves a number of longer term and related initiatives:

- Systematic and staged refurbishment and replacement strategy, leveraging the initiatives addressed within the newly instituted Asset Management Plan.
- Integration of the Circuit Health Coordinators with the ESSS Inspection Program (providing an over-inspection role and coordinator in addressing high-priority reliability related inspection deficiencies/exceptions), and Reliability Engineers.
- Prioritization of workload with the concept of protecting the feeder backbone and addressing circuits with multiple customer interruptions.
- Recruiting and hiring of additional distribution line and substation personnel (in advance of the planned retirement of a rapidly aging workforce) and using this temporary increase in staffing to address the corrective maintenance backlog.

As CEI implements these recommendations and integrates them with the existing comprehensive system reliability improvement program, we need to reinforce that the current infrastructure though aged and in relatively poor material condition, is not the main cause for CEI missing its reliability targets. However, to get to the performance levels called for in the current agreement between the Staff and CEI and sustain that level of performance, these issues could become the controlling factors in the future.

1.4.3 Organization and Staffing

The entire discussion to this point highlights the initiatives and practices necessary to meet the 2009 reliability performance targets and sustain that level of performance for the foreseeable future (nominally 10 years). An underlying assumption and critical success factor is the capacity and ability of the Company's staff to carry out the plan as it is integrated with the Company's strategic and operational plans. With that in mind, we performed an assessment of the Company's organization and staff, looking at it from three critical dimensions:

- **Sustainable Workforce:** Addressing CEI's ability to maintain its staffing levels and knowledge base at a level sufficient to carry out its mission with respect to system reliability.

  Table 1-9 shows the Departments/Functions/Positions that were the focus of this portion of the assessment.

Figure 1-9
Critical Staffing Categories

Department	Function	Positions
Reliability	Regional Dispatching	Regional Dispatcher
Operations Services	Distribution Line	Line Leader Shift Lineworker Leader Distribution Lineworker
	Engineering Services	Engineer Distribution Specialist
Operations Support	Substation	Relay Tester Electrician Leader
	UG Network	Underground Electrician Leader Shift Underground Electrician Leader Underground Electrician

- **Workforce Management:** Evaluating CEI's ability to keep pace with its inspection and maintenance requirements, improve outage response, and execute the capital spending plan (specifically New Business and reliability/capacity projects).
- **Reliability Culture:** Focusing on CEI's effort to ensure that its sustainable and well-managed workforce is aligned (at all levels) to the requirement to improve overall system reliability.

Current Organization and Staffing (and any enhancements) will have little if any immediate positive impact on CEI meeting its 2009 Reliability Performance Targets. However, failure to confront the issues in an urgent and comprehensive manner will compromise the Company's ability to achieve the objective of 10 years of sustained 1st and 2nd quartile reliability performance.

The three elements of organization and staffing are obviously interrelated in that a sustainable workforce, properly staffed and aligned to the priorities of the organization will balance the inspection and maintenance, outage response, and capital project requirements. In terms of current status across these three dimensions, there are two areas that we consider critical in support of the long-term vision:

- The challenge of replacing a rapidly aging work force within a fairly tight O&M budget; and
- The need to address the CM backlog across all line districts.

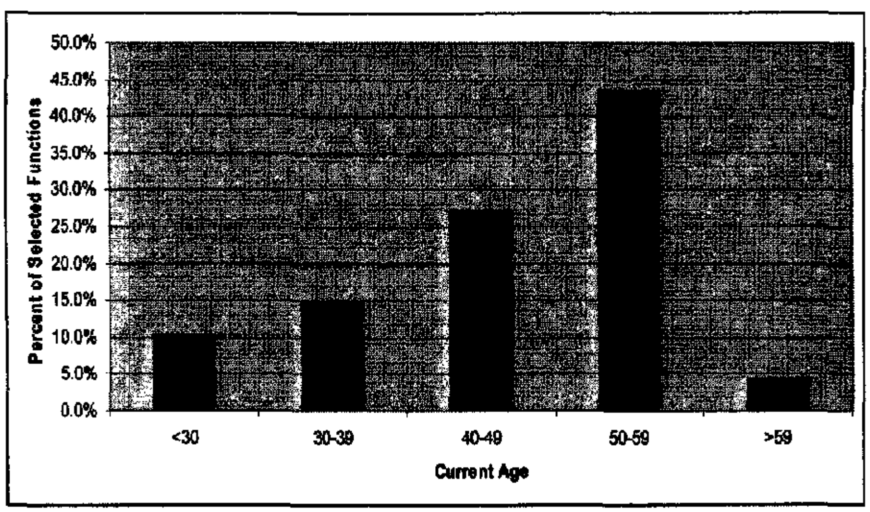
Aging Work Force

Figure 1-10 below presents the age profile of the staff within each of the functions shown in the above table (Figure 1-9). Over 48 percent (308 employees) are 50 years of age (or older) and are likely to retire within the next 10 years. The current policy of *maintaining a one-for-one hiring policy with respect to managing attrition is certainly* valid when doing "like for like" replacements in terms of experience, knowledge, and leadership acumen. The reality is that the Company is replacing the more seasoned individuals with "entry level" hires. Though the PSI program provides an outstanding foundation for a new hire, it does not replace the 3-5 year apprenticeship period necessary to become fully productive in the field, let alone the value provided by someone with over 20 years of field experience.

The impact of this dynamic is already being felt among the Regional Dispatchers where 35 percent of the staff has less than 2 years experience. This cannot help but have a short term negative impact on service restoration.

Figure 1-10
CEI Employees by Age and Function

Function	Current Age					Total
	<30	30-39	40-49	50-59	>59	
Substation	13	7	29	60	11	120
Distribution Line	42	60	96	152	14	364
Underground Network	1	11	16	25	0	53
Engineering Services	6	10	20	33	3	72
Regional Dispatching	5	6	13	10	0	34
TOTAL	67	94	174	280	28	643
PERCENTAGE	10.4%	14.6%	27.1%	43.5%	4.4%	



Related to the issue of an aging workforce is the fact that over 55 percent (38 of 68) of the current Leadership and Management staff in these targeted areas is also likely to retire within this same 10-year time period. The pipeline for future Leaders and Managers is typically composed of the Non-Managers (included in Figure 1-10) that currently range in age from 30-39); this pipeline is clearly constrained.

To mitigate these effects FirstEnergy has taken a number of steps to address this challenge, most notably the PSI Program. The PSI program could certainly be categorized as an industry "Leading Practices" approach to recruiting, training, and assimilating entry level employees. The challenge is the pace at which this staffing shortfall, a decade in the making, can be addressed. This is particularly acute given the other realities of budget and headcount constraints and general availability of labor. Unfortunately, there is no shortcut to developing future leaders and managers. This will require an aggressive outside recruiting effort, coupled with a well-conceived leadership and management development program.

Corrective Maintenance Backlog

Figure 1-11 portrays our assessment of the Company's performance across the major work streams that compete for resources on a day-to-day basis. In short, CEI has maintained a fairly good balance, with one notable exception: Distribution (Line) Corrective Maintenance. There are a number of parallel actions to take in addressing this shortfall:

- Explore opportunities to out-source more capital project work, thus freeing up the distribution line resources to address open exceptions/deficiencies identified during the circuit inspections.
- Establish a more effective prioritization process with respect to identified deficiencies/exceptions ranging from highest priority (reliability and/or safety related) to inconsequential (no action required).
- To the extent that an accelerated hiring program is instituted, apply the temporary "excess staff" to closing out the CM backlog.

Figure 1-11
Workforce Management Assessment

Measure	Performance	Comments
Substation Preventive Maintenance		Significant PM Backlog on track for resolution by EOY 2007 (with existing staff levels)
Distribution Line Preventive Maintenance		Mix of in-house staff (light duty personnel) and staff supplementation with contractors (former CEI employees)
Substation Corrective Maintenance		Current staff able to keep pace with exceptions identified during substation inspections
Distribution Corrective Maintenance		Significant backlog. Resolution hinges on accelerated Senior level replacement strategy/increase in contracted work
Outage Response		Steady improvement in response time (CAIDI) noted since 2003
Capital Spending		On track. Increase in contracting Capital Projects will free CEI resources to address Corrective Maintenance

LEGEND

	ON TRACK
	CAUTION
	DANGER

1.4.4 Asset Management

The issues relating to capital expenditures, refurbishment/replacement of an aging infrastructure, and organization and staffing will be comprehensively and programmatically addressed as the Company transitions to the Asset Management Business Model. Our overall interpretation of this more global initiative in the context of the reliability assessment is straightforward – we believe it absolutely represents the greatest opportunity for the Company to make rapid, cost-effective, and truly sustained improvement in electric system reliability. At the same time, we also believe it represents perhaps the single greatest risk to overall system reliability because of the potential uncertainties created by any major organization restructuring and new processes.

Figure 1-12 below summarizes some of the major risks and opportunities that CEI will face as it develops its Asset Management organization:

Figure 1-12
Opportunities & Risks of First Energy's Asset Management Initiative

Opportunity	Risk
FirstEnergy-wide "best thinking" and "best practices" applied to the CEI system	Local technical and reliability expertise is diminished by a strong centralizing reorganization
Economies of scale asset data analysis, systems & tools, and equipment purchases	Unnecessary data collection not linked to key asset reliability decisions
Circuit Health Coordinators (CRCs) with strong, local accountability for circuit performance.	Inadequate skills and qualifications of CRCs in a critical role; diminished sense of accountability in other departments
Vastly improved asset data and inspection performance.	Uncertain or unclear organizational relationships for or interfaces with new functions

This initiative is simply in too early a stage to make any formal assessment of its effectiveness or impact on CEI's overall reliability. However, we recommend that this initiative be actively monitored for impact and effectiveness over the next 12-24 months.

1.5 Summary of Recommendations

The following recommendations present our view of the actions that will bring CEI into compliance with the 2005 ESSS Rule 10 Action Plan (and more specifically to meet the 2009 SAIFI and CAIDI targets). Many of these items have already been initiated or implemented, providing further evidence of the sense of urgency and importance CEI assigns to meeting these commitments. Sections 2.0 through 8.0 of this report not only expand upon the factors that drive these recommendations (offering additional suggestions and insights related to positioning CEI as an example of "best practices" in the area of electric system reliability), but they also address in more detail the challenges and opportunities related to achieving the longer-term 10-year vision.

Note that the "Impact" described in the table below combines the potential of a specific recommendation to impact reliability (as measured by SAIFI and/or CAIDI) with our assessment of the current capabilities of the CEI staff. As the Company's expertise and associated competencies improve (particularly in the area of lightning protection), these initiatives can yield further improvements in overall reliability.

The Tier 1 initiatives summarize the *impact* and estimated cost of actions where the Company will achieve the highest "value" for the capital and/or O&M dollars expended. The Tier 2 initiatives outline the next level of actions to fully address the current gap (and then some) between the 2006 performance and the 2009 targets. Figure 1-13 provides a tabulation of the impact and associated incremental costs:

Figure 1-13
Reliability Impact and Cost Summary

	SAIFI		CAIDI	
	Impact	Cost	Impact	Cost
Tier 1	(.17)	$5.8M	(20 minutes)	$0.225M
Tier 2	(.13)	$17.6M	(5 minutes)	$0.100M
Total	**(.30)**	**$23.4M**	**(25 minutes)**	**$0.325M**

For SAIFI we recommend (as a minimum) adopting all the tier one actions and the tier 2 actions for sectionalizing the feeder backbone (SI-4). This presents the most cost-effective solution as this combination of Tier 1 and Tier 2 results in a projected SAIFI reduction of 0.20 from 2006 actual performance at an incremental cost of $7.8 million. For CAIDI we recommend implementing all the actions summarized in Section 1.5.2 and discussed more comprehensively in Section 6.5, resulting in a reduction of 25.0 minutes at an incremental cost of $325,000.

In terms of establishing the baseline from which to measure the SAIFI and CAIDI impacts, we have adopted the following approach (working in conjunction with CEI Management):

- CEI's 2006 SAIFI performance was 1.17 (almost identical to the 12-month rolling measure as of the end of September 2007). Therefore, we suggest maintaining the 2006 performance level as the SAIFI baseline.
- CEI's 2006 CAIDI performance was 128.3 minutes. CEI has, in fact, implemented a number of improvement measures over the past few years that have yielded significant improvement to CAIDI (the Year-to-Date CAIDI for 2007 is 105.5 minutes). Admittedly, 2007 has been a "good" year in terms of storms (particularly those "minor storms" that almost reach the threshold for exclusion); thus, it would not be prudent to use that figure as the baseline. However, applying a historical perspective to this year's performance level, one can normalize the 105.5 minutes to a more representative and conservative number (from which to apply the impacts of these recommendations). Since a "typical" year" has, on average, 4 storms that do not quite make the threshold criteria for a major storm (i.e. excludable); and there have been none in 2007, we suggest adjusting the CAIDI baseline to 120.0 minutes (assumes 4 storms with the average experienced CAIDI impact of 3 to 4 minutes).

Therefore, full realization of these recommendations will result in an estimated overall SAIFI of less than 1.00 and a CAIDI of 95.0 minutes. Informed readers should recognize that there are a number of other factors that could impact the bottom-line achievement of these goals that have no relation to the effectiveness of these recommendations (particularly with respect to CAIDI). It is quite probable that as CEI adopts these recommendations, these other variables will come into play. For example, the reduction of subtransmission, substation, and backbone outages could shift the mix of outages from those of relatively short *duration* to those with longer duration. In a sense, the success of the SAIFI initiatives can negatively impact progress on CAIDI. These types of effects can be analyzed and accounted for should they occur, adding more emphasis to the importance of close communication and coordination between CEI and the Staff to ensure a constructive dialogue that acknowledges accomplishments and promotes joint problem-solving should these variances be realized.

1.5.1 SAIFI Improvement Recommendations

(Refer to Section 5.5 for more discussion around the proposed actions)

SI No.	Action	Tier	SAIFI Impact	Incremental Cost	Completion Date
SI-1	Enhanced Tree Trimming	Tier 1	(.026)	$1M ($48 per CI avoided)	12/31/2008
		Tier 2	(.020)	$3M ($200 per CI avoided)	NOTE 1
SI-2	Lightning Protection	Tier 1	(.010)	$1M ($133 per CI avoided)	12/31/2008
		Tier 2	(.067)	$11.3M ($225 per CI avoided)	NOTE 1
SI-3	Line/circuit inspection and repair prioritization scheme	NA	(.035)	$0.5M ($19 per CI avoided)	12/31/2009
SI-4	Sectionalize the Backbone	Tier 1	(.093)	$2M ($29 per CI avoided)	9/30/2008
		Tier 2	(.033)	$2M ($59 pre CI avoided)	5/31/2009
SI-5	Replace three-phase reclosers with single-phase reclosers	NA	Negligible Based on Number Planned for 2007	$20K per Retrofit and $125 per CI avoided	NOTE 2
SI-6	Selectively apply instant trip/ timed re-close	NA	33 circuits with instant trip off	No incremental cost	NOTE 2
SI-7	Inspect, maintain, test and repair/replace as necessary 4kV exit cable	Tier 1	(.01)	$1.3M ($159 per CI avoided)	12/31/2008
		Tier 2	(.005)	$1.3M ($397 per CI avoided)	
SI-8	Use Worst Performing Devices information to develop a worst-CEMI program	NA	Limited Impact (Customer Satisfaction)	Additional cost not related to improving SAIFI	NOTE 2
SI-9	Replace failure-prone URD cable	NA	Limited Impact (Customer Satisfaction)	Additional cost not related to improving SAIFI (already budgeted)	NOTE 2
SI-10	Integrate the Circuit Health Coordinators with the ESSS Inspection Program	NA	CI Avoidance	No incremental cost (*previously budgeted*)	NOTE 2
SI-11	Continue to address the operability of switches on the subtransmission system	NA	Prevent deterioration of subtransmission SAIFI	No incremental cost (previously budgeted)	NOTE 2
SI-12	Continue to replace circuit breakers and relays at the substations	NA	Prevent deterioration of substation SAIFI 5 breaker replacement projects scheduled for 2008 – expected SAIFI improvement of (0.014)	No incremental cost (previously budgeted) $1.0M for 5 breaker replacement projects	NOTE 2

NOTE 1: Our initial recommendation acknowledges that the cost-benefit trade-offs for these tier 2 actions do not warrant CEI action at this time.

NOTE 2: These actions are either situational (with little or no anticipated impact to overall system reliability) or already in full implementation (where any incremental improvement to SAIFI has largely been realized). They are provided for purposes of management visibility as they are viewed as complimentary (necessary) to the 2009 objectives.

1.5.2 CAIDI Improvement Recommendations

(Refer to Section 6.5 for more discussion around the proposed actions)

ID No.	Action	Tier	CAIDI Impact	Incremental Cost	Completion Date
SR-1	Systematize staff Pre-mobilization	Tier 1	(6 minutes)	$100,000 ($2.22 per 100 CMI	6/30/2008
		Tier 2	(5 minutes)	$100,000 ($2.66 per 100 CMI)	6/30/2008
SR-2	Fully implement partial restoration for OHL ("Cut and Run") and URD ("Split and Hit")	NA	(4 minutes)	$125,000 ($4.17 per 100 CMI)	NOTE 3
SR-3	Fully implement use of the alternate shift	NA	(4 minutes)	No incremental cost	NOTE 3
SR-4	Recruit/Train New Dispatchers	NA	NOTE 4	No incremental cost	NOTE 3
SR-5	Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007)	NA	(1 minutes) in 2008/2009 Additional (2 minutes) after 2009	No incremental cost (already included in the budget)	12/31/2009
SR-6	Reevaluate Level of Staffing with respect to outage response	NA	NOTE 4	Undetermined	NOTE 3
SI-1 to SI-7	Impact of CI reduction on CMIs	NA	(5 minutes)	Defined within SI-1 to SI-7	12/31/2008

NOTE 3: These actions are already in full implementation; improvement in both areas is called for, requiring constant reinforcement and monitoring.

NOTE 4: The impact on CAIDI is indeterminate in that the intent of these actions is to proactively avoid a negative impact to CAIDI

1.5.3 Long-Term Recommendations

The foundational elements that comprise an integrated approach to realizing sustained performance over a 10-year period are discussed in Sections 7.0 and 8.0 of this report. As such, the benefits to be derived in terms of SAIFI and CAIDI cannot be specifically quantified, nor are they necessarily "an action". In fact, these specific initiatives are properly categorized as key elements to the Asset Management Strategy just being formulated at the FirstEnergy level and are being implemented within the Operating Companies as this report was being prepared. They are being listed here for the purpose of establishing visibility and to ensure the linkage of this strategy to the overall result of this assessment:

- Maintain Capital Spending at the level currently planned for 2008 ($84.7 million) for a minimum of 5 years. Note that this budget level includes both Transmission and Distribution.
- Establish and adhere to "Reliability-related" investments (which could include capacity projects as well) at levels, percentage-wise, commensurate to those for 2007.
- Consistent with the development of the Asset Management Strategy develop a comprehensive plan to replace and/or refurbish the current electric distribution infrastructure, while in parallel implementing the shorter-term reliability measures identified in Sections 1.5.1 and 1.5.2.
- Accelerate hiring to facilitate the assimilation of new personnel in advance of anticipated attrition (due to retirement). CEI's plans to increase head count by 50 in 2009 (payroll increase of $2.5-3.0 million) and then maintain pace with attrition presents a rationale approach to the challenge of replacing an aging work force while remaining committed to the PSI program. In fact, the increase in headcount will provide a 2-year acceleration with respect to replacing senior staff (refer to Figure 7-22).
- Work cooperatively with the Staff to redefine the ESSS Inspection Requirements (focus, frequency and follow-up of exceptions) so that they more appropriately align with achieving the 10-year vision.

1.6 About UMS Group

UMS Group is a private consultancy headquartered in Parsippany, New Jersey. Founded in 1989, UMS Group also has offices in the United Kingdom, Dubai, and Australia. UMS Group has served more than 300 utility clients around the globe.

The website www.umsgroup.com provides extensive information about the company, its services, clients, and experience.

The UMS Group project team for this assessment was composed of the professionals described in the following subsections.

1.6.1 Jeffrey W. Cummings

Mr. Cummings is a Principal at UMS Group with extensive consulting and core business process reengineering experience with utility clients in North America.

His experience includes over 25 years of management, engineering, and marketing experience in the utility industry. His experience includes strategic and business planning and implementation, and organizational change management. Mr. Cummings has a diverse background in power generation, as well as in transmission, distribution and substation planning and design.

Prior to Joining UMS, Mr. Cummings owned and operated his own consulting practice. He also served for 11 years in various leadership capacities at a major engineering and technical services corporation. He holds a Master of Science Degree in Operations Research from the U. S. Naval Postgraduate School.

1.6.2 Daniel E. O'Neill

Dan O'Neill is President and Managing Consultant of O'Neill Management Consulting, LLC, specializing in serving utility clients. He has personally led more than fifty engagements with many of the largest utilities as his clients, and has played a leading role in T&D reliability and asset management, speaking at conferences, publishing in industry journals, and acting as a resource for his colleagues and for many in the industry.

In addition, Mr. O'Neill has over twenty-two years of industry experience, including four years as a utility financial executive and the remainder with major consulting firms serving the industry. Besides his asset management and reliability work, he has consulted on decision analysis, activity-based budgeting, work management, and information systems planning.

He holds a Ph.D. in economics from MIT, taught at Georgia Tech's College of Industrial Management, and is past president of the Atlanta Economics Club and of The Planning Forum's Atlanta Chapter.

1.6.3 James M. Seibert

Mr. Seibert is a Principal with UMS Group's Energy Delivery practice and has served as the Managing Director of its Middle East and European business unit. He has 18 years of experience as a management consultant to electric & gas utilities in the Transmission, Distribution, Customer Service and Shared Services functions. Prior to joining UMS Group in 2001, Mr. Seibert was most recently a Vice President and a Director of the Energy Delivery practice at Navigant Consulting, where he spent over 8 years leading process improvement, operations analysis, and merger integration efforts. Prior to his work at Navigant Consulting, Mr. Seibert spent 5 years as a Senior Consultant with Andersen Consulting (now Accenture) where he led projects to develop Customer Information Systems and Work Management Systems at major electric and gas utilities.

Mr. Seibert holds a Master of Business Administration degree from the University of Chicago and a Bachelor of Science degree in Industrial & Systems Engineering from the Ohio State University. He is also licensed as a C.P.A.

2.0 Electric Infrastructure Review

2.1 Purpose

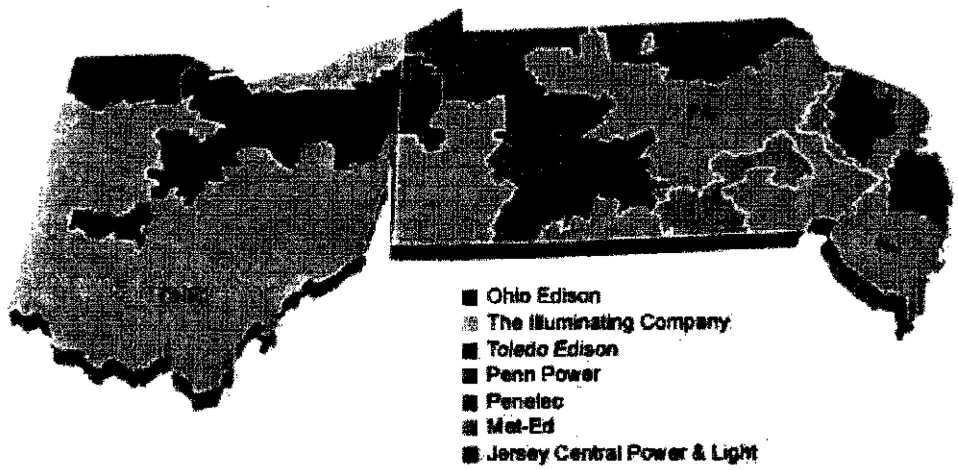
The purpose of this section of the report is to summarize our review of CEI's electric system infrastructure with a specific focus on its impact on reliability. Our approach was designed to satisfy three specific goals:

- ***Verify the accuracy of the system condition records*** via a selected sampling of records across CEI's 2 substation areas and 9 line districts. This sample was developed in a collaborative effort among UMS Group, PUCO staff, and CEI, with a bias towards inspecting the worst-performing circuits and substations. Our objective was expressly not to conduct a statistically rigorous sample of the entire system; however, the sample was intentionally constructed with a modest scale to represent as much as possible the geography, customer density, system design and voltage levels (specifically 4 kV, 13.2 kV, and 34.5kV) of the system. Presuming that we could conclude that the records accurately depict the material condition of the electric system, UMS Group would then proceed to analyze and assess the current condition of the electric system infrastructure based on a further records-only review and compare it to other similarly configured utilities using the Company's existing asset condition and health records and asset age data.
- ***Visually assess the physical condition of this same sample of system assets*** relative to industry standard. Though the majority of the system condition assessment would be made using CEI's records (provided they proved to be materially accurate as noted above), we saw this additional element as a necessary yet efficient way to augment our efforts by physically assessing the condition of the electric system.
- ***Determine the effectiveness of and adherence to CEI's Field Inspection policies and practices***. While inspecting the cross-section of substations and lines across all areas and districts, UMS Group conducted a simultaneous review of the field inspection policies and procedures (and the Company's compliance thereof) and used this review of the selected cross-section of the system to determine if the Company's policies and practices are achieving the desired outcome. The specific details of our insights, findings, and conclusions regarding this review are contained within Section 5.0 of this report.

2.2 Overview of the FE/CEI Electric System

FirstEnergy (also referred to as "FE") is a diversified energy company headquartered in Akron, Ohio. Its subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity; marketing of natural gas; and energy management and other energy-related services. Its seven electric utility operating companies comprise the nation's fifth largest investor-owned electric system, serving 4.4 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. FirstEnergy's Corporate Vision is to become the leading retail energy and related services supplier in their region.

Figure 2-1
First Energy Operating Company Territories



The Cleveland Electric Illuminating Company (The Illuminating Company or "CEI") serves 761,972 customers over an area that spans 1,683 square miles. Its electric system consists of over 200 distribution substations (with 640 transformers and 2,386 circuit breakers) and 1,375 distribution and subtransmission circuits with 13,874 miles (8,473 overhead and 5,401 underground) of line and 149,943 distribution transformers. This assessment focused on the following:

- 4kV Distribution: The majority of 4340V systems are within the municipal limits of the City of Cleveland and the immediately surrounding suburbs, with some "islands" outside this area where as the 4800V systems are found east of State Route 306.
- 13.2kV Distribution: The 13,200V systems are found in municipal areas that developed subsequent to 1960.
- 34.5kV Subtransmission: The 36,000V subtransmission systems are found throughout the CEI service territory except in Downtown Cleveland. They supply the larger commercial and industrial customers and distribution substations.

CEI also has a rather expansive 11kV subtransmission system (approximately 300 circuits) constructed almost exclusively as a ducted underground system providing service directly to CEI distribution substations and large three-phase customer vaults in addition to a 120/208 V secondary network. As such they have built in redundancy and are therefore rarely a source of significant number of customer interruptions. Therefore, this portion of CEI's Reliability Assessment did not address the 11kV system.

2.3 Scope and Approach

As a precursor to this review, 15 circuits were selected by totaling the number of Customer Minutes of Interruptions (CMIs) from 2002 to 2006 and noting those circuits that were candidates for a "worst-performer" classification, while ensuring proper representation across the 4kV, 13.2kV and 34.5kV distribution and subtransmission systems as well as the 9 line districts. Similarly, 4 substations were selected in consultation with PUCO staff, with a bias towards those substations with prior equipment reliability issues. Figures 2-2 and 2-3 below identify and provide key demographic information on the selected circuits and substations.

Figure 2-2
Listing of Inspected Lines and Circuits

Voltage	Circuit	OH Line Miles	No. of Poles
34.5kV	40004-0014	25	857
	40181-0019	17	529
	40159-0021	33	1026
13.2kV	50152-0030	4	163
	40109-0008	8	337
	40156-0010	6	191
	40120-0019	4	206
4kV	40024-0003	39	553
	40218-0002	92	2823
	40132-0003	12	532
	40141-0006	10	390
	40049-0001	9	358
	40052-0003	10	455
	40190-0001	68	1364
	40124-0003	10	403
	TOTAL	347	10,187

Figure 2-3
Listing of Selected Substations

Substation	Description	Number of Transformers	Number of Breakers
40169	138/36kV	9	33
40180	13kV	2	6
40126	13kV	1	5
40092	4kV	3	10
	TOTAL	15	54

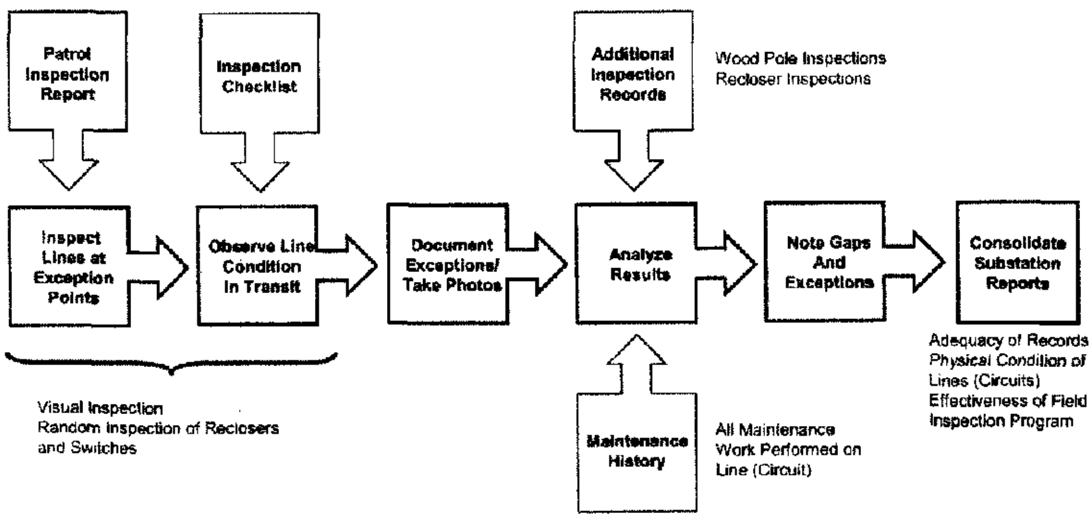
We conducted this inspection through a process that included standardized inspection checklists (refer to Section 2.6 for the format of these checklists) for both the Lines/Circuits and Substations inspections to enhance the accuracy and comparability of our results.

2.3.1 Line/Circuit Inspections

UMS Group conducted an overall visual inspection of the lines/circuits with a random inspection of reclosers and switches. Figure 2-4 below provides a description of this process where the most recent patrol inspection report was used in conjunction with the UMS Group inspection checklist to identify, document, and photograph exceptions. These results were then compared with the various company inspection reports (Wood Pole and Reclosers) and Maintenance Records to assess the completeness and accuracy of the Company's records.

Figure 2-4 below summarizes the inspection and analysis process.

Figure 2-4
Lines / Circuits Inspection and Analysis Process



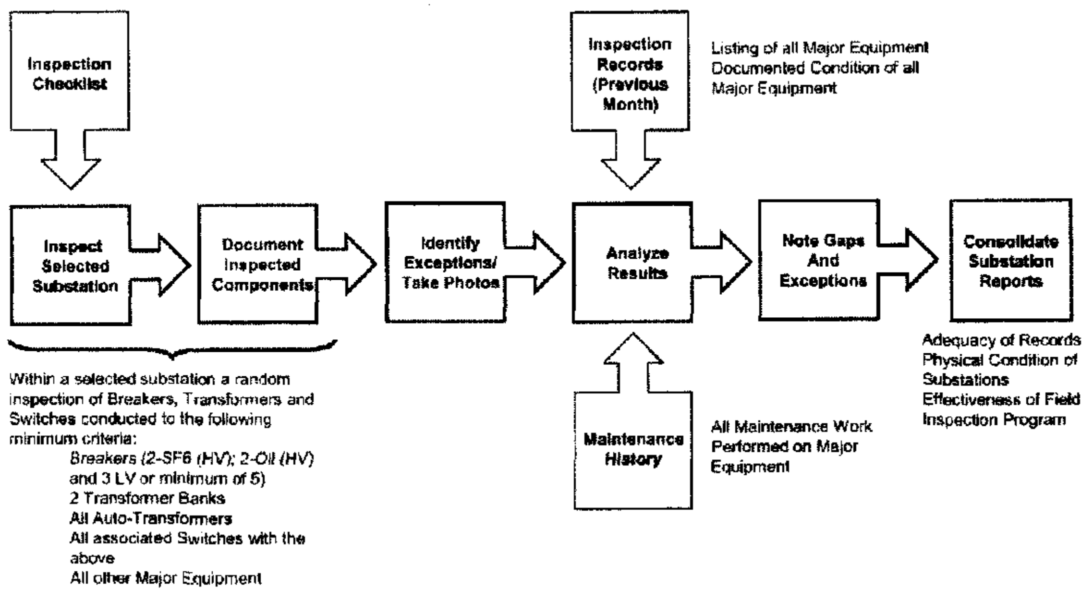
2.3.2 Substation Inspections

UMS Group systematically performed a random inspection of circuit breakers, transformers, and switches adhering to the following minimum criteria:

- Breakers: 2-SF6 (HV); 2 Oil (HV) and 3 LV (or minimum of 5)
- 2 Transformer Banks
- All Auto-Transformers
- All associated Switches with the above

Figure 2-5 below outlines the process that we followed in assessing the adequacy of records, the physical condition of the substations, and the effectiveness of the Field Inspection Program (discussed further in Section 5.0). As with the Lines/Circuits Inspections, all noted exceptions were documented (photographs were taken) and compared with the Company's existing inspection and maintenance history. In so doing, exceptions were noted, compared with the inspection records (to verify that they had been previously identified), and correlated to the maintenance records (to gain insights into the Company's follow-up activities that result when discrepancies are identified).

Figure 2-5
Substation Inspection and Analysis Process



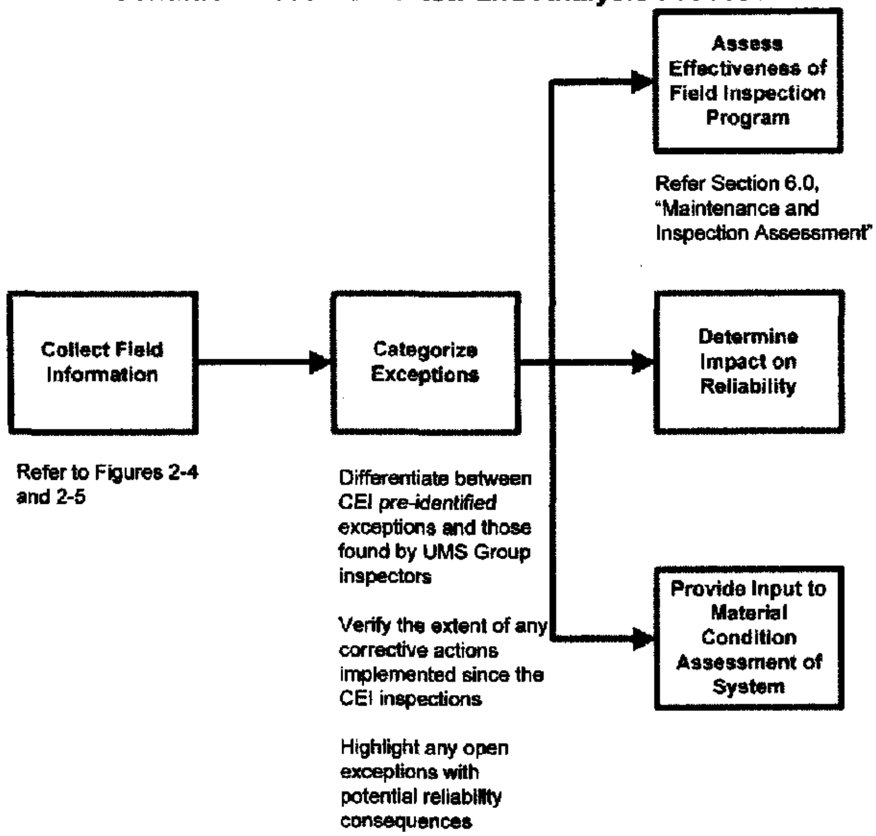
2.4 Results of the Assessment

In assessing the overall results of this review our comments here are focused on the adequacy of the inspection records and the material condition of the assets from the view of their impact to overall system reliability. The challenge was to develop a methodology that effectively answered the following questions:

- Can the inspection records (and as an extension all electric distribution records) be used to accurately assess the material condition of the assets?
- Are there any insights, recommendations, and conclusions that can be developed from this information to address the overriding objective of improving overall system reliability (as measured by SAIFI and CAIDI).

Figure 2-6 below provides a high level view of the process we followed to accomplish this charter. Its objective was to translate raw field inspection data into information and then develop a number of insights and conclusions.

Figure 2-6
Condition Records Review and Analysis Process



2.4.1 Summary of Results

Figure 2-7 below provides a tabular view of the lines/circuits inspection exceptions (and exception discrepancies). Among the sampled circuits there were originally 303 exceptions identified by CEI inspectors across the 15 circuits. The UMS Group inspectors noted an additional 132 exceptions on these same circuits. Thus, at the time of our inspection a total 320 remaining exceptions (CEI had addressed 115 of the original 303 exceptions) existed on the sample circuits. Of these "open" exceptions, 128 were identified as having a potential impact on reliability (e.g. vegetation management, broken cross arm/cross arm laying on a conductor, damaged pole, or damaged lightning arrestor).

Figure 2-7
Lines/Circuits Inspection Results

Voltage	Circuit	CEI INSPECTIONS					UMS ASSESSMENT		
		CEI Inspection Date	Pre-Identified Exceptions	Pre-Identified Corrected	Pre-Identified Uncorrected	Past Due Uncorrected	UMS Exceptions Found	Total Remaining Exceptions	Open Reliability Exceptions
34.5kV	40004-0014	9/1/2004	0	0	0	0	23	23	14
	40181-0019	3/7/2006	22	19	3	NA	14	17	17
	40159-0021	2/11/2005	7	5	2	2	3	5	5
13.2kV	50152-0030	7/10/2007	6	0	6	NA	0	6	4
	40109-0008	12/1/2005	53	13	40	40	19	59	9
	40156-0010	7/1/2003	49	19	30	30	13	43	22
	40120-0019	3/7/2006	0	0	0	NA	13	13	11
4kV	40024-0003	3/1/2006	1	0	1	NA	6	7	7
	40218-0002	4/1/2006	101	18	83	NA	14	97	16
	40132-0003	9/8/2004	3	3	0	0	1	1	0
	40141-0008	7/1/2005	17	17	0	0	4	4	3
	40049-0001	6/1/2003	13	2	11	11	14	25	12
	40052-0003	7/10/2007	5	0	5	NA	5	10	3
	40190-0001	2/20/2007	16	10	6	NA	0	6	2
	40124-0003	11/1/2005	10	9	1	1	3	4	3
TOTAL			303	115	188	84	132	320	128

Figure 2-8 below shows that the substation condition records are more than adequate. Of the 11 pre-identified exceptions (i.e. reported by CEI inspectors), all but 3 had been corrected by the time of our independent review. Furthermore, the 8 exceptions found by UMS Group are typical findings for the monthly inspection cycle (e.g. oil leaks and high/low oil) and there are no reliability related exceptions noted for the 4 inspected substations.

Figure 2-8
Substation Inspection Results

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
40169	7/10/2007	9	33	7	5	2	0	7	9	0
40180	7/10/2007	2	6	2	2	0	0	0	0	0
40128	7/10/2007	1	5	1	1	0	0	1	1	0
40092	7/11/2007	3	10	1	0	1	0	0	1	0
TOTAL		15	54	11	8	3	0	8	11	[illegible]

The positive outcome of the initial inspection results in substations suggested that our attention should focus further on the less favorable outcome in Lines / Circuits. Consequently, the remainder of this discussion will focus on distribution lines and circuits.

Figures 2-9 and 2-10 below provide two views of our further analysis. First, an analysis of those exceptions that could cause customer interruptions by voltage (specifically 34.5kV, 13.2kV and 4kV) and second, a review of the year the lines/circuits were last inspected.

Figure 2-9 below present the exceptions by voltage class and type. At first glance there seems to be little, if any, systematic differentiation of inspection results among the different voltage levels.

Figure 2-9
Reliability Related Exceptions by Voltage Class

Voltage	# Poles	RELIABILITY RELATED EXCEPTIONS				Total
		Vegetation Management	Cross Arm (Broken or Conductor)	Damaged Pole	Damaged Lightning Arrestor	
34.5kV	2412	4	26	3	3	36
13.2kV	897	18	24	3	1	46
4kV	6878	14	16	10	6	46
TOTAL	10187	36	66	16	10	128

Figure 2-10 below presents the distribution of exceptions based on the year the lines/circuits were last inspected. It also appears somewhat inconclusive. Obviously, the existence of any exception that could lead to a customer interruption is a concern; particularly those on circuits inspected during 2003-2005 that were previously identified with reliability related exceptions and remain uncorrected. However, in the context of 347 miles of OH lines/circuits and 10,187 poles, the number of reliability related exceptions noted (128) is not considered of sufficient quantity to warrant overriding attention. The greater concern is the accumulated effect of many exceptions system-wide, their effect on the overall material condition of the system, and the long term impact on CEI meeting the reliability targets and maintaining them for a 10-year period.

Figure 2-10
Reliability Related Exceptions by Inspection Date

Last Inspection	# Poles	RELIABILITY RELATED EXCEPTIONS				TOTAL
		Vegetation Management	Cross Arm (Broken or Conductor)	Damaged Pole	Damaged Lightning Arrestor	
2003	549	17	10	6	1	34
2004	1389	1	10	1	2	14
2005	2156	5	11	3	1	20
2006	4111	10	33	4	4	51
2007	1982	3	2	2	2	9
TOTAL	10187	36	66	16	10	128

Maintaining the focus on the open exception items that could potentially impact reliability (and more specifically those exceptions that can cause customer interruptions), the 128 reliability-related exceptions were reviewed and prioritized based on whether they pose an "immediate" threat to system reliability. In reviewing the inspection reports (and photographs), the existence of a conductor on a cross arm, a broken cross arm and inoperable lightning arrestor were highlighted as higher priority than the other exceptions.

The results of this review are highlighted in Figure 2-11 below.

Figure 2-11
Reliability Related Exception Analysis

Exception	MOST RECENT CEI INSPECTION				
	2003	2004	2005	2006	2007
Conductor on Cross Arm	1	0	0	4	1
Broken Cross Arm	2	7	5	11	0
Arrestor Open	1	2	1	4	2
TOTAL	**4**	**9**	**6**	**19**	**3**
Open Reliability Exceptions	**34**	**14**	**20**	**51**	**9**
Open Exceptions	**68**	**24**	**72**	**134**	**22**

The conclusion is that of the 320 open exceptions (combined CEI and UMS Group inspections) noted on the 15 selected circuits, 128 were categorized as reliability related; 41 of which are significant enough to potentially cause an outage.

2.4.2 Adequacy of System Condition Records

As a result of their general level of completeness and accuracy, UMS Group validated the assumption that an assessment of the current condition of the electric system infrastructure can be based on a records-only review (rather than a further, detailed field inspection effort). Based on this interpretation we present the following additional conclusions:

- **Line/Circuit Inspections:** The CEI line/circuit-related inspections (ranging from 2003 to 2007) did not capture all material exceptions and point to a need to "tighten up" the Field Inspection Program. However, it is our view that 132 exception discrepancies (in the context of 347 miles of overhead lines/circuits and 10,187 poles represented by the inspection sample) do not compromise the insights developed from these and other records regarding the material condition and/or reliability of CEI's electric distribution system.
- **Substations:** With respect to substations, UMS Group identified 8 potential discrepancies (i.e. items not previously noted on CEI's inspection reports). Due to the nature of these exceptions (oil leaks and low or high oil levels), it is quite likely that these occurred during the time period since the last inspection.

Though the discrepancies noted in this section will likely have a negligible impact on overall system reliability (in the short term), they have a more strategic imperative with longer range implications on system reliability. The Company recognizes this and is taking action to improve its performance in this area as part of the ongoing Asset Management (AM) implementation. A key component to this initiative is the collection and analysis of asset health data. With the introduction of the newly commissioned Circuit Reliability Coordinators (CRC) role as part of the AM initiative, CEI has an opportunity to improve these inspections.

FirstEnergy has also formed a new corporate department – Policy, Process, Procedures & Assessment (PPPA). This department will be responsible for developing detailed procedures across many of the FirstEnergy policies and processes (including Distribution Inspection and Maintenance Practices), and will establish and monitor performance assessment points within the established procedures.

2.4.3 Material Condition of the Assets

The overall condition of CEI's electric distribution system (based on our records review of the Company's infrastructure) presents a significant challenge to CEI reaching top quartile performance in SAIFI and second quartile performance in CAIDI (i.e. the industry context of CEI's current reliability targets), particularly given the mandate to sustain this performance over a ten year period.

Based on our review of the most recent CEI System Assessment, the following major asset condition areas will need to be addressed:

- Staged upgrading and/or replacement of transformers, particularly those built with GE Type U bushings.
- Replacement of substation equipment in many of the 4kV substations (and a few 36kV substations) due to concerns regarding the availability of replacement parts.
- Pre-1930 vintage manholes (there are over 9300 manholes in the system with a median age of 75 years).
- Addressing pre-WWI vintage conduit systems that are experiencing problems with deterioration of fiber ducts.
- Addressing over 1,600 circuit miles of the 4kV, 11kV, and 36kV underground system that is primarily cabled with non-jacketed 3-conductor PILC (with a median age of over 60 years). With an anticipated continually increasing failure rate (currently experiencing 5-7 failures per 100 circuit-miles annually), these systems are being systematically upgraded.
- Distribution Wood Poles have a median age of 32 years (over 350,000 in the system) and are experiencing a reject rate of about 4.3 percent.
- Subtransmission Wood Poles have a median age of 40 years (over 20,000 in the system) and are experiencing a reject rate of about 9 percent.
- UD Cable is being replaced at the third failure in a section. There are currently over 3,300 circuit-miles of UD Cable installed in the system.
- 36kV Pole Fire Mitigation, Line Switch Maintenance/Replacement, and Aging Wood Pole Hardware is being addressed as part of the 36kV line rebuild work.

A significant contributing factor to this level of necessary asset condition-related investment has been the systematic under-investment in the electric system that occurred during the 1990s (as outlined in Section 8.0 of this report) rather than any perceived breakdown in the Maintenance and Inspection Programs. The solution will necessarily involve a well-conceived and staged revitalization program, which will be conducted as part of FirstEnergy's Asset Management Transformation initiative.

2.4.4 Reliability Impact

Though 40 percent of the 320 open exceptions represent potential causes of customer interruptions, less than 35 percent of those pose any imminent threat to overall system reliability. Though that number is not considered statistically significant in terms of impacting near-term reliability (particularly given the number of circuit-miles and poles represented by the 15 circuits), there is a concern that the accumulated effect of many exceptions will have a compounding impact, as they do contribute to the overall material condition of the system, and will eventually compromise the goal of meeting the reliability targets and maintaining them for a 10-year period.

2.5 Inspection Checklists

The attached checklists were used by the inspectors to conduct the Distribution Infrastructure Review outlined in the project work plan. The actual inspection records, including these checklists and accompanying photographs, are available upon request.

CEI Substation Inspection Checklist

Substation: **Date:**

Battery

Check electrolyte level to be proper	Yes/No	
Check and record battery voltage	Voltage	
Check battery room heaters to be on	On/Off	
Check battery grounds		
Positive	Yes/No	
Negative	Yes/No	
Check for cracked cells	Yes/No	
Overall battery room condition	Describe	

Control House

Locked/Secure	Yes/No	
Clean	Yes/No	
Switchgear		
Indicating Lights	On/Off	
Doors Latched and Tight	Yes/No	
General Condition - ok	Yes/No	

	Total Number	Type Relay	Last Tested Date
Relay Inventory			
For Breakers			
For Transformers			
For Transformers			

Describe Concerns

Breakers - LV

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Oil breakers- check oil level correct	Yes/No				
Oil filled bushings-check oil level correct	Yes/No				
Record SF6 pressure	Psi				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Breakers - HV, Oil

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Oil breakers- check oil level correct	Yes/No				
Oil filled bushings-check oil level correct	Yes/No				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Breakers - HV, SF6 Gas

		Breaker #	Breaker #	Breaker #	Breaker #
Counter Reading	Record				
Control cabinet heater	On/Off				
Record SF6 pressure	Psi				
Check bushings for chips/cracks	Yes/No				

Describe if Yes

Check for oil/hydraulic leaks	Yes/No				

Describe if Yes

Check for equipment grounds installed	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Busses

Check for broken/cracked insulators	Yes/No	

Describe if Yes

Check for varmint proofing	Yes/No	

Describe if Yes

Visual for signs of heating,flashover,etc	Yes/No	

Describe if Yes

Capacitor Banks

Check for blown fuses	Yes/No	
Check for bulging/leaking capacitors	Yes/No	

Describe if Yes

Check for equipment grounds installed	Yes/No	

Motor Operators

		MO #	MO #	MO #	MO #
Check and record counter readings	Record				
Check heaters	On/Off				
Check for rodent problems (mice, rats, ants)	Yes/No				

Describe if Yes

Station/General Facilities

Fencing

Grounding	Yes/No	
Washes	Yes/No	
Gates Locked	Yes/No	
Vegetation	Yes/No	
Trash	Yes/No	

Describe Concerns

Switches- HV

	Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Broken/missing arcing horns	Yes/No				
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

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Switches-LV

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

		Switch #	Switch #	Switch #	Switch #
Chipped/cracked porcelin	Yes/No				
Contacts properly seated	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

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Switchgear

		Breaker #	Breaker #	Breaker #	Breaker #
Indicating lights working	Yes/No				
Counter readings	Record				
Check for equipment grounds installed	Yes/No				
Rodent problems/varmint proofing installed	Yes/No				
Lighting arresters ok	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

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Transformers

		Bank #	Bank #	Bank #	Bank #
Record LTC/Regulator counter reading	Record				
Check bushing oil levels ok	Yes/No				
Check high and low side lighting arrestors ok	Yes/No				
Main Tank and LTC oil levels	Record				
Oil Temperatures					
Hot spot - Found/Max	Record				
Top Oil - Found/Max	Record				
LTC oil - Found/Max	Record				
Check for equipment grounds installed	Yes/No				
Oil leaks					
Main tank	Yes/No				
LTC	Yes/No				
Condition of paint ok	Yes/No				
Oil spill containment condition	Yes/No				
Visual for signs of heating,flashover,etc	Yes/No				

Describe Concerns

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Describe any overall observations not included above.

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Circuit Inspection Check List

Date: ____________

District ______________________ **Substation** ______________________

Structure/Pole # ______________________ **Circuit #** ______________
Inspector: ____
Location: ____

Cross Arm Condition ______________________________
Cross Arm Brace Condition ______________________________
Pole Condition ______________________________
Insulator Condition ______________________________
Pole Leaning ______________________________
Pole Tag (Device on Pole) ______________________________
Bushing Condition ______________________________
Cutout Condition ______________________________
Arrester Condition ______________________________
Bracket Condition ______________________________
Grounds ______________________________
Guy ______________________________
Guy Guard ______________________________
Spacer ______________________________
Oil Leaks ______________________________
Vegetation Clearance ______________________________
Floating/Damaged Conductor ______________________________
Wildlife Protection ______________________________

Additional Information:

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____
____
____
____

Reclosure Inspection Checklist

Circuit: **Date:**

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

Pole Location
Size of Reclosure
Wildlife Protection
Electronic or Hydraulic
Counter Reading
Lightning Protection
Overall Condition

3.0 Outage History and Cause Analysis

3.1 Purpose, Scope, and Approach

The purpose of this section is to describe our analysis of the Company's five-year history of outage events to determine the major factors that influence system reliability and identify the company's key opportunities for cost-effective reliability improvement. Our presentation of this analysis will be accomplished by a systematic review of a series of analytical tables that will show the relationships between various outage "drivers" and aspects of system performance such as:

- Year, season, time of day, and major weather conditions,
- Cause – tree (preventable and non-preventable), lightning, animal, etc.,
- Impact – number of customers affected, duration of outage,
- Type of device interrupted – circuit breaker, recloser, line fuse, transformer, etc.,
- Specific location of equipment – district, worst circuits, worst devices, and
- Voltage, line length, overhead/underground construction

Our overarching objective is to form a clear interpretation of the specific causes of outages at as detailed a level as the system data will allow. We will then use these insights to identify the specific actions and recommendations the Company can take to improve reliability. These detailed recommendations are presented in Sections 5.0 and 6.0 of this report, the impact and cost of which are summarized in the Executive Summary.

3.2 The Outage Database

CEI uses FirstEnergy's PowerOn application as its Outage Management System (OMS). PowerOn is a General Electric-designed product and is one of the leading OMS applications used in the U.S. electric utility industry. It was originally developed to be compatible with the SmallWorld Geographic Information System (GIS), which is also a GE application and one of the most widely used GIS products. PowerOn has also been successfully integrated with other GIS databases, as is the case with FirstEnergy (which uses Autodesk's GIS Design Server product.)

Outage Orders are completed by the CEI Dispatcher in the PowerOn OMS. Each Outage Order goes through a "Review and Approve" verification process where a supervisor reviews the Order's data integrity and approves the Order. The review includes data fields such as cause code, duration, staged restoration steps, and other criteria which are reviewed for accuracy and compared to the EMS log. Once approved, the outage records are transferred to the Enterprise Data Warehouse (EDW) for management reporting.

The structure of the CEI outage data is similar to that of typical electric utility outage databases. Specifically, the data model is organized around the outage event - which at its core consists of the following information for each outage:

- Outage ID number,
- Time Off (when the outage began, i.e. when the power went off),
- Time On (when the outage ends, i.e., when the power came back on),
- Device ID – the unique ID of the interrupting device (fuse, breaker, etc.),

- Customers Interrupted (CI) – the number of customers downstream of the device,
- Cause, and
- Comments.

From these basic fields other performance data can be computed, such as the duration of the outage and the Customer Minutes of Interruption (CMI, the product of duration and CI). Note that CI is the numerator of SAIFI (and the denominator of CAIDI) and CMI is the numerator of CAIDI (and SAIDI). Other fields that are often included are:

- Circuit, Substation, and District (which can be deduced from the interrupting device and a system configuration /connectivity model),
- Repair Done,
- Line Down Indicator,
- Major Storm Indicator (to flag which records should be included for non-storm),
- Non-Outage Indicator (for records that are ultimately judged to not fit the definition of an outage, either because they are less than 'n' minutes in duration, were due to excludable causes (Customer Equipment), or were false alarms),
- Lockout Indicator – whether the interrupting device was a circuit breaker that ultimately locked out after perhaps trying to re-close a number of times,
- Line Type Indicator – for overhead or underground construction,
- Voltage, and
- Weather – as recorded by the dispatcher for the day or period.

A noteworthy aspect of all modern outage management systems is that they allow for the distinction between an outage and its partial restoration steps. In these systems, the individual records are actually outage restoration steps (rather than an entire event), each with its own number of customers interrupted and duration and a separate ID for each step (and a common Outage ID for all steps that are part of the same outage).

The outage database provided for this analysis contained most of these fields (except for voltage, line type, and line down). In addition, FirstEnergy provided a separate database with the characteristics of each feeder, including line miles of overhead and underground, (voltage is indicated by the *circuit name*, e.g. L is 13.2kV, H is 4kV, V is 11kV and R is 36kV). The data provided by FirstEnergy was adequate to perform the analysis outlined in this section.

3.3 Trends in Key Performance Statistics

The focus of this analysis is on ***non-storm*** SAIFI and CAIDI performance, with a specific focus on performance for the 5-year period ending 2006. "Non-storm" is defined as all outages not part of a major storm event, which is further defined as any event where 6 percent of the Company's customers are affected during a 12-hour period (or, occasionally other events which are approved by the PUCO as "excludable"). Figure 3-1 below provides a five-year view of the key performance statistics for CEI's reliability based on the information analyzed from the PowerOn dataset noted above.

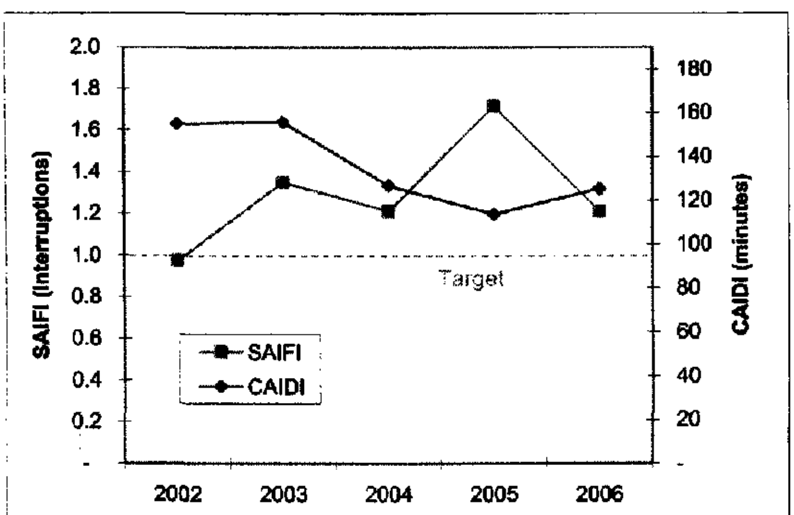
Figure 3-1
Five Year Summary of Key Reliability Measures

		2002	2003	2004	2005	2006
Outages	Non-Storm	6,918	5,881	5,934	7,419	7,770
CI	Non-Storm	717,517	932,418	846,068	1,234,999	875,992
CMI	Non-Storm	110,796,914	156,335,383	111,309,573	141,040,088	112,382,533
Customers	Served	752,666	762,226	743,595	729,838	747,026
SAIDI (minutes)	Non-Storm	147.21	205.10	149.69	193.25	150.44
SAIFI (interrupts)	Non-Storm	0.95	1.22	1.14	1.69	1.17
CAIDI (minutes)	Non-Storm	154.42	167.67	131.56	114.20	128.29

Special Note - The data shown in Figure 3-1 above originates from an updated database and does not precisely match the information reported to PUCO. The variance between this presentation and prior report is approximately 1 minute for CAIDI/SAIDI and less than 0.1 for SAIFI.

The non-storm SAIFI and CAIDI data from Figure 3-1 above is shown graphically in Figure 3-2 below. When this presentation is compared with the 2006 Interim Goals and 2009 Target, it is obvious that CEI needs to both eliminate interruptions (SAIFI) and improve restoration (CAIDI).

Figure 3-2
Five Year Trend in Key Reliability Measures



From Figure 3-2, except for an anomaly in 2005 when SAIFI spiked to 1.71, CAIDI steadily improved through the period to 2005 (it has since leveled out) and SAIFI has been fairly constant (ranging between 1.21 and 1.35 since 2003). While the leveling off is encouraging, the Company clearly needs to improve to reach the 2009 targets as outlined in Figure 3-3 below:

Figure 3-3
CEI Reliability Performance Targets

	SAIDI	SAIFI	CAIDI
2006 Actual	150.4	1.17	128.3
2006 Interim Goal	127.7	1.11	115.0
2007 Interim Goal	116.6	1.06	110.0
2009 Target	95.0	1.00	95.0

In reviewing the 2006 actual performance against target, it should be noted that had it not been for a storm late in the year (one that just missed meeting the storm exclusion criteria) and the major heat storm (a 1 in 50-year event) during the July 30th-August 2nd time period (also not excluded because it did not meet the 12 hour requirement), the Company would have met its 2006 Interim Goal. Figure 3-4 below further highlights this point.

Figure 3-4
2006 Storm Exception Impact

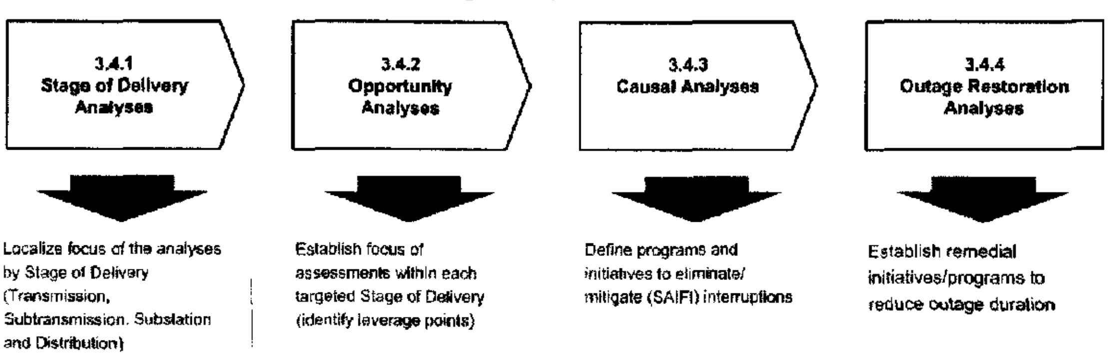
	CIs	CMIs	PCNT of Customers	Adjusted SAIFI	Adjusted CAIDI
Late Storm	39,266	11,096,490	5.4%		
Heat Storm	57,028	13,873,370	7.6%		
W/O Both	96,294	24,969,860	N/A	1.05	112.4

The FirstEnergy and CEI management team fully recognizes that a "miss is a miss" and are committed to meeting the goals in spite of these "one-off" occurrences. We highlight this point only to illustrate that the gaps in performance (vs. targets) on a year-to-year basis are not always as wide (or necessarily indicative of a systematic issue) as they might at first appear. To meet the requirement of a ten-year sustainable performance level in SAIFI and CAIDI, the recommendations outlined in this report and the Company's actions will have to account for normal conditions and these "if only" or "one-off" scenarios.

3.4 Framing the Reliability Issues

Having established an overall perspective of CEI's performance relative to the reliability targets in the previous section, the next phase of this assessment involves defining the focus of the analysis (framing the reliability issues). Figure 3-5 below outlines the analysis approach that we have followed to further focus our work.

Figure 3-5
Reliability Analysis Framework



3.4.1 Stage of Delivery Analyses

When examining the reliability of an electric system, it is useful to disaggregate the system into its sub-systems ("stages of delivery") namely:

- Transmission Substations and Lines ('Bulk Power'),
- Subtransmission (mainly 36kV lines),
- Substation ('Distribution' and 'Subtransmission" Substations), and
- Distribution (Feeders, Taps, Secondary, and Services).

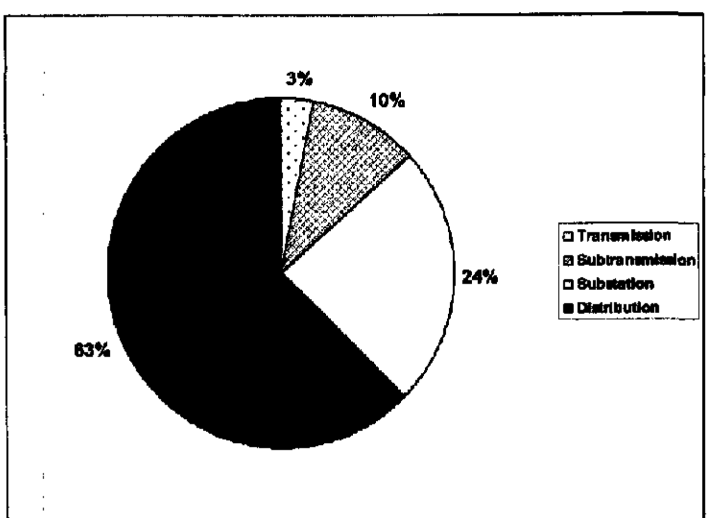
Figure 3-6 below shows a disaggregation of non-storm SAIFI performance by stage of delivery.

Figure 3-6
Trends in Non-Storm SAIFI Minutes by Subsystem

Subsystem/Stage of Delivery	2002	2003	2004	2005	2006
Transmission Substations and Lines	.02	.13	.07	.02	.04
Subtransmission	.13	.34	.23	.45	.12
Substation	.38	.36	.35	.51	.29
Distribution	.45	.52	.56	.73	.76
Total	**.97**	**1.35**	**1.21**	**1.71**	**1.21**
Distribution % of Total	**46%**	**39%**	**46%**	**43%**	**63%**

It is evident from the data above that through 2005 CEI had reliability challenges across all dimensions of distribution (subtransmission, substation and distribution circuits/lines). Moreover, recent Company efforts (most notably proactive thermal imaging, installation of SCADA controlled sectionalizers, improving the operability of the switches on subtransmission, replacing feeder breakers and relays, and improving animal protection on substations) have yielded sufficient improvement to allow us to focus primarily on Distribution (with respect to identifying additional improvement opportunities). Figure 3-7 below further illustrates that point.

Figure 3-7
2006 SAIFI by Stage of Delivery



Therefore, the remainder of this analysis will ***focus on distribution (feeders)***, noting that the initiatives already implemented for the Subtransmission and Substation stage of delivery need to continue.

3.4.2 Opportunity Analysis

The next step in disaggregating the performance of the electric system is to investigate how CEI might better focus its resources and maximize the effectiveness of its reliability improvement initiatives. We believe that five areas warrant detailed investigation:

- 'Size' of the components that experience interrupting faults (Number of Customers Impacted)
- Lockouts (Feeder Breaker Outages)
- Location of the outages (Reliability by District)
- Voltage (4kV, 11kV *and* 13.2kV)
- Worst Performing Circuits

<u>Number of Customers Impacted</u>

By focusing on the "size" of the components that experience the interrupting faults, our analysis segmented the outages by number of customers interrupted during an outage. At the lowest level, a single customer may have been interrupted by an outage to the service line to his premise. One level up from that is a transformer outage that typically may have interrupted a few more customers, maybe as many as ten. From there, the outage may have occurred on a small fused tap, a large fused tap, or the entire circuit. Figure 3-8 below shows the distribution of outages by the number of customers affected.

Figure 3-8
Mix of Outages by Outage Size

Customers	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1-10	55%	52%	51%	50%	51%
11-100	37%	36%	36%	37%	36%
Over 100	8%	12%	13%	13%	13%

It is clear from Figure 3-8 above that each year over half of all outages occurred close to the customer premise, interrupting only 1 to 10 customers. Each one of these outages often requires the same level of effort to restore service as one affecting thousands of customers, i.e., a truck must go to the site, evaluate the damage, and either make immediate repair or call for more resources to repair the damage. In other words, if a tree falls on a line and takes down the conductor between two poles, the repair required will be to replace the span, whether the number of customers interrupted is two or two thousand (as it could be in the latter case, if the span was part of the 'backbone' or un-fused main branch of the feeder).

Despite this effort, if the number of customers affected is small, there will be little (if any) impact on system reliability. These small outages need to be addressed in the context of avoiding repeat offenders (i.e. worst performing devices) to avoid customer satisfaction issues but not as part of the strategy to address overall system reliability as measured by SAIFI and CAIDI.

By contrast, as Figure 3-9 below shows, the distribution of *customers interrupted* by the 'size' of the interrupting device is skewed heavily in the opposite direction - toward the 'larger' devices. In fact, the devices that interrupt only 1 to 10 customers make up less than three percent of the total number of customers interrupted. This means that if CEI could somehow (presumably, at great expense) completely eliminate all of the 'small' outages; it would only reduce SAIFI by an almost negligible amount.

Figure 3-9
Breakdowns of Customer Interruptions by Outage Size

Customers	2002	2003	2004	2005	2006
1-10	4.3%	2.7%	2.6%	2.6%	2.6%
11-100	23.7%	17.3%	16.4%	15.4%	15.4%
Over 100	72.0%	80.0%	81.0%	82.0%	82.0%

The distribution of *customer minutes of interruption* provides the same insight as noted in Figure 3-10 below.

Figure 3-10
Breakdowns of Customer Minutes by Size of Outage

Customers	2002	2003	2004	2005	2006
1-10	5.3%	3.3%	3.4%	3.5%	3.5%
11-100	29.7%	22.7%	22.6%	20.5%	21.5%
Over 100	65.0%	74.0%	74.0%	76.0%	75.0%

Summarizing Figures 3-8, 3-9, and 3-10, we note that 51 percent of the distribution outages interrupted less than 10 customers, accounting for less than 3 percent of all distribution customer interruptions and less than 4 percent of all distribution customer minutes of interruption. Similarly, 87 percent of the distribution outages interrupted less than 100 customers, accounting for less than 18 percent of the distribution customer interruptions and 25 percent of the distribution customer minutes.

Alternatively, by focusing on a select 13 percent of the distribution outages (those affecting more than 100 customers) CEI can address over 82 percent of the distribution customer interruptions and 75 percent of the distribution customer minutes. This insight leads to the Company developing strategies where SAIFI and CAIDI improvements can be achieved by avoiding and/or mitigating the impact of 'large' outages (i.e., ones interrupting a large number of customers per outage); typically outages on the 13.2kV feeder backbone (every part of the circuit that is not behind a fuse) or very large taps and the 4kV feeders with high customer densities.

Specific initiatives that focus on these high impact improvement opportunities are discussed in more detail in Sections 5.0 and 6.0. They include initiatives aimed at:

- Hardening the feeder backbone via enhanced vegetation management, inspection and repair of pole and pole-top fault-causing equipment problems, lightning protection, and animal mitigation.

- Sectionalizing, meaning the installation of additional reclosers in targeted protection zones as well as the fusing of unfused taps.

Feeder Breaker Outages

The observation (above) that the greatest opportunity to significantly improve reliability lies in avoiding and/or mitigating the impact of large outages suggests that a further delineation of the outage data focused on circuit breaker "lockouts" may identify additional insights. Figure 3-11 below classifies the Company's 5-year history of lockouts and their relationship to outages (both number and minutes).

Figure 3-11
Five Year Impact of Lockouts

Measure	2002	2003	2004	2005	2006
Number of Outages	6918	5881	5934	7419	7770
Lockouts	222	238	223	234	323
Percent	3%	4%	4%	3%	4%
Customer Interruptions	335237	397933	414126	535487	565720
Lockouts	122647	122915	132250	128432	204230
Percent	37%	31%	32%	24%	36%
Customer Minutes	57653857	82933697	73159764	89334243	84092521
Lockouts	14468258	17164817	17179475	13168922	19307315
Percent	25%	21%	23%	15%	23%

A review of Figure 3-11 above yields the following insights:

- Of the 13 percent of the outages that impact more than 100 customers, 33 percent (4 percent of the total number of outages) were feeder breaker lockouts.
- Lockouts contributed 24 to 37 percent of all customer interruptions and 15 to 25 percent of all customer minutes. By simply reducing the number lockouts by 50 percent, all things being equal, CEI would improve SAIFI to between 0.99 and 1.06.
- In 2006, non-lockout customer interruptions fell by approximately 10 percent, but lockout customer interruptions increased by 60 percent, suggesting some changes in network protection schemes over the past few years.

Interestingly, since 2003 the percent of customer interruptions originating from lockouts does not appear to vary by distribution voltage. Figure 3-12 below highlights the impact of lockouts by voltage.

Figure 3-12
Impact of Lockouts by Voltage

Voltage	Measure	2002	2003	2004	2005	2006
4kV	Number of Customer Interruptions	236779	203391	305075	365731	389369
	Lockouts	74399	69814	93895	85488	138909
	Percent	31%	34%	31%	23%	36%
13.2kV	Number of Customer Interruptions	98234	96029	108881	169354	176158
	Lockouts	48141	52909	38263	42721	65210
	Percent	49%	55%	35%	25%	37%

Therefore, linking this portion of the analysis with the analysis of number of customers interrupted suggest the Company-led efforts that focus on both the first zone of the