Large Filing Separator Sheet

Case Number: 08-935-EL-SSO

File Date: 10/15/2008

Section: 2 of 2

Number of Pages: 94

Description of Document: Testimony of David W. Cleaver

The underlying cause is two-fold:

- Inadequate funding for over a decade (commencing in the early-1990s), an occurrence that was common across the industry.
- 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).

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 equipment/component 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 evaluated 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-Section 7.0), 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 be mindful 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.

5.5 Summary of Recommendations

The following recommendations are submitted recognizing that many of them are more appropriately characterized as extensions of programs already in place. In most cases a more systematic approach (focused on the portions of circuits/lines that potentially impact the most customers) balanced with appropriate attention to customer satisfaction issues (e.g. elimination of multiple customer interruptions); CEI can realize a stepped improvement in SAIFI towards the 2009 goal of 1.0.

SI-1	Enhance tree-trimming program to address overhanging limbs and structurally weak trees on the feeder backbone

<u>Discussion</u>

In 2006, and comparably in 2004 and 2005, approximately 95,000 customer interruptions (CI) are attributable to the cause "Tree Non-Preventable". Of these, in 2006, 41,000 CI (more than 40 percent), are lockouts (presumably due to outages in the first zone from the circuit breaker to the first recloser, not counting taps), and 31,000 (more than 30 percent) are on the three-phase part of the line, which, while not always true backbone, is a reasonable proxy for purposes of analysis. Moreover, the lockouts are split approximately two-to-one (66 percent to 33 percent) between the 13kV and 4kV respectively, except that in 2006 the 13kV are unusually high, at 85 percent. Finally, the lockouts on the 13kV numbered 29 events on 27 circuits, while on the 4kV the lockouts numbered 19 on 17 circuits.

Therefore, it is reasonable to assume that if enhanced tree trimming were done on approximately 50 circuits (reviewing a list from 2004-2006 and using some judgment to select the best candidates) a substantial improvement could be achieved in future years. Experience elsewhere suggests a 50 percent improvement can be achieved by a program such as the one described above. This would yield approximately a 21,000 reduction in CI, or, in terms of SAIFI in 2008, a SAIFI impact of .026 interruptions for the average customer.

The cost of such a program would typically be about $20,000 per circuit, or $1 million, (recall that this would be done only on the first zone) and classified as an O&M expense. Periodic maintenance of this enhanced clearance would add some future cost, but the removal, where it happens, might partially offset that. Roughly, this program would cost $48 per CI avoided. This might be viewed as an appropriate 'first tier' of such a program. We highly recommend such an effort.

The second tier would be to address the outages on the rest of the backbone beyond the first zone. With the same effectiveness of 50 percent, this would yield an additional improvement of 15,000 CI, for an additional SAIFI impact of .020. The cost of the second tier would be considerably higher because it would be required on more circuits (approximately 100 make the list each year of circuits with lockouts on the backbone past the first zone) and most likely more mileage per circuit. A reasonable estimate of the additional cost for the second tier might be $3 million, making the unit cost approximately $200 per CI avoided. We believe this second-tier effort should be considered within the context of overall cost and benefit of achieving the reliability goals.

SI-2	Ensure lightning protection initiatives focus primarily on the feeder backbone, continuing to replace damaged arresters, but also consider adopting a more strategic approach by integrating FALLS and NLDN data with other contributing factors (e.g. type of construction, grounding, shared structures). NOTE: CEI is planning to replace lightning arresters at 3 substations in 2008.

Discussion

To gauge the impact of lightning protection, it will be useful to examine the lightning-caused CI in 2004-5, before the coding changed, on the theory that a comparable number of lightning-caused outages continued to occur in 2006, but were coded as line failure, equipment failure, or unknown. In those years, approximately 150,000 CI were due to lightning, again with a two-to-one ratio of 13kV to 4kV CI. Of these, only about 10 percent occurred as lockouts, i.e., in the first zone of the backbone, yielding a 15,000 CI target for a first-tier program. Only about 20 circuits would be involved. The cost of a properly focused program (more than just adding lightning arresters) would be approximately $50,000 per circuit, and might be expected to achieve at least a 50 percent reduction in lightning-caused first-zone CI's, i.e. a 7,500 CI reduction, for a SAIFI impact of .010, on an expenditure of $1 million, or $133 per CI avoided.

The second tier would target the two-thirds (2005) to four-fifths (2004) of lightning-caused CI that occurred on the three-phase line outside of the first zone, i.e. more or less the rest of the backbone. Thus, a program aimed at lightning protection of the backbone would focus conservatively on around 67 percent of the 150,000 CI per year, or a 100,000 CI target. Again, the split between 13kV and 4kV would be about two to one.

Under the same assumptions about program intensity, 50 percent effectiveness would yield a 50,000 CI reduction, or a SAIFI impact of .067. The expenditure would be much higher, however, since it would involve more than 150 circuits, with more mileage per circuit. Estimating $11.25 million, the second tier of backbone lightning protection would have a unit cost of $225 per CI.

SI-3	Apply a line/circuit inspection and repair prioritization scheme that focuses initially on the feeder backbone, then in areas where customers experience multiple outages (worst performing circuits and devices, and as a last priority, those areas that have lesser impact on system reliability.

Discussion

While the standard line inspection and repair program includes the backbone of each circuit, this program emphasizes the need to pay particular attention to the backbone of those circuits that continue to experience a high number of backbone outages, i.e., which typically interrupt a large number of customers.

The main focus would tend to be backbone outages due to three causes: equipment failure, line failure, and wind, but over the period 2004-2006 the coding of wind and lightning changed, making it somewhat more difficult to identify the targeted CI. In 2006, the total backbone CI (including lockouts and all three-phase outages as a proxy) for the four categories of equipment failure, line failure, wind and lightning was 380,000 CI. Subtracting the targeted lightning CI of 115k CI, we arrive at a reasonable 265,000 CI target for the line inspection and repair program. It is worth noting that the 380,000 CI can be identified as coming mainly from approximately 100-13kV circuits and 200-4kV circuits, and that the split of CI between 13kV and 4kV was closer to 1.5 to 1 rather than the 2-to-1 ratio shown in other analyses.

The effectiveness of a backbone inspection and repair program is dependent on prioritizing the repairs, and limiting them to the conditions most likely to give rise to a fault in the near future. Many fault-causing conditions are not readily apparent from inspection, being internal to the part that fails, e.g., conductor, splices, insulators, etc.

A reasonable estimate of effectiveness is that a program like this might achieve a 10 percent reduction in CI on the 300 or so circuits to which it might be applied. This translates to a 26,000 reduction in CI, or a SAIFI impact of .035.

The cost of this program can be viewed as an increment to the existing 5-year line inspection and repair program that is done for the entire circuit, and as such might only involve an additional $0.5 million per year of O&M expense. With the assumed 10 percent improvement in CI, this would imply a unit cost of $19 per CI avoided. As such, there is no compelling need to have multiple tiers for this program. The key to success will be, however, the focus on reducing backbone outages through identification and repair of fault-causing conditions on the circuits that have shown a tendency toward such. As well, our comments regarding the diligence with which the inspection and repair program identifies such conditions and resolves them are relevant here.

SI-4	Further sectionalize the 13.2kV feeder backbone (123 circuits with 500 or more customers that do not have reclosers installed are potential candidates), and review for possible sectionalizing, the 230-4kV circuits with more than 500 customers. NOTE: CEI will install 5 36kV SCADA controlled sectionalizers in 2007 and is planning to continue this initiative in 2008. NOTE: Memos were released to the design groups to install 14 reclosers, 61 sectionalizers, and 145 sets of fuses in 2007.

Discussion

Since sectionalizing the backbone targets the entire population of backbone outages, regardless of cause, it is appropriate to note that almost 700,000 CI per year were due to lockouts and three-phase outages in 2004 through 2006, with an approximately two-to-one ratio of 13kV CI to 4kV CI. Of those 700,000 CIs, lockouts normally run about 15 percent, but in 2006 they rose to almost 30 percent. Unlike the tree and lightning programs, however, the sectionalizing program is best divided into tiers not by whether it is first zone but by the number of backbone CI experienced on average per circuit, either because they had a high number of backbone events or because they had a high number of customers impacted. Once again, we find a two-to-one ratio of 13kV to 4kV opportunities. In fact, if we screen the circuits by how many lockout CI they have had in the period 2004-2006, we find that there are seventy-five 13kV circuits with more than 6,000 backbone CI in total over the three years (2,000 backbone CI per year), and thirty-eight 4kV circuits that meet that same criterion. An appropriate focus for a first-tier sectionalizing program would be approximately 100 circuits. The average annual number of CIs for those circuits represents a 350,000 CI target, averaging 3500 backbone CI per circuit per year.

Each switch applied to those circuits may be assumed to cost $20,000 when fully installed, assuming that what is often used as the sectionalizing device is a bank of three single-phase sectionalizers. One hundred such devices could be installed for a cost of $2 million.

The effectiveness in reducing CI, as applied to the target figure, would depend on the configuration of each circuit, which is a level of detail beyond the scope of this study. If, for example, the circuit had no reclosers on it at all, which is true of many of the CEI circuits, then it might be assumed that two switches might be installed, one at the midpoint and one at a tie-point at the end of the backbone. Such an installation might be expected to reduce lockout CI on that circuit by 50 percent, or 25 percent per switch. This figure is often cited in studies of sectionalizing effectiveness when no reclosers exist. At the same time, the use of three single-phase sectionalizers instead of one, affords the possibility that only one-third of the customers might be interrupted by a downstream fault behind the sectionalizing device, raising the effectiveness of a mid-point sectionalizer from 25 percent to 41 percent.

In practice, there are many complications that prevent developing a clear scenario, including the presence of existing reclosers (which complicates the computation of effectiveness, since it limits the amount of line exposure that the recloser effectively controls), the difficulty in finding a single tie-point that could carry the whole back end of the circuit, etc. If, for example, a circuit already has three reclosers on it, then achieving even a 25 percent reduction may require an additional sectionalizing device for each zone that has a high number of feeder backbone CIs.

For purposes of estimation of program impact, we assume that the installation of an additional sectionalizing device on a circuit would reduce the backbone CI for that circuit by 20 percent, which, for this population of 100 circuits would yield a 70,000 CI reduction, for a SAIFI impact of .093 interruptions for the average customer, at a unit cost of $29 per CI (or $2 million) avoided.

The second tier of such a program might address another 100 circuits (costing another $2 million), whose average annual backbone CI per year might comprise a 176,000 CI target, which, with a 20 percent effectiveness, would yield a 35,000 CI reduction, for a SAIFI impact of .047, at a unit cost of $57 per CI avoided. Since the current work plan calls for completion of this second tier in May 2009, the 2009 impact should be adjusted accordingly (to .033).

SI-5	Identify opportunities to replace existing three-phase reclosers with single-phase reclosers (should be considered on a case-by-case basis, depending on the needs of the customer, and the impact to a major commercial or industrial customer that requires three-phase power). NOTE: CEI will replace 4 three-phase reclosers with single phase closers in 2007.

Discussion

As our discussion of SI-5 makes clear, a mid-point recloser that would normally mitigate 25 percent of interruptions in the zone which it bisects, i.e., the two zones which it created when it was installed can be credited with mitigating a higher percentage if it is a bank of single-phase reclosers instead of a single three-phase recloser. In each case, due consideration of all three-phase customers in the downstream zone must be given, and, any limit the application of this principle somewhat. Also, the effectiveness of a program of retro-fitting banks of single-phase reclosers will be dependent on the frequency with which faults occur on only one phase.

In the extremes, if there were no single-phase faults, the retrofit would be useless, and if they were all single-phase faults, the retrofit would increase the sectionalizing device's effectiveness from 25 percent to 42 percent. A reasonable assumption would be an increase from 25 percent to 33 percent (which would be appropriate if half of the outages were single-phase), or an 8 percent improvement in sectionalizing effectiveness. The target of that improvement would be all the backbone outages in that zone.

If we approach this analysis from a basis of the average zone to which it might be applied, we see that if a zone covering 1000 customers had two outages per year, then without the recloser there would have been 2,000 CI, and the recloser can be credited with saving 25 percent, or 500 CI. If the recloser were a bank of single-phase reclosers, it might be expected to save 33 percent, or 660 CI, for a net improvement of 160 CI. The cost of the retrofit would be approximately $20,000, so the unit cost of the program is $125 per CI avoided.

At present CEI has identified only four locations in 2007 where it saw an opportunity to employ this tactic. This would amount to a cost of $80,000 and an improvement of 640 CI reductions, or a virtually negligible SAIFI impact. Without further knowledge of the individual circuits and customers involved, we can only suggest that the method be employed in those instances in which the economics warrant it, e.g., where there a large number of single-phase backbone faults and where customer considerations allow it.

SI-6	Analyze application of instant trip and timed re-close on a circuit-by-circuit basis, considering the nature of the circuit and its customers, the history of success with instant trip/timed re-close on the circuit, and any damage that might be done if the instant trip is not set.

Discussion

This recommendation is oriented to further study of this issue, with particular emphasis on keeping the instant trip on if the study indicates it is often successful in clearing faults. Since at present, CEI only has a limited number of circuits without the instant trip, this is not expected to improve SAIFI much, but merely prevent it from deteriorating.

SI-7	Inspect, maintain, test and repair or replace (as test results indicate) the 4kV exit cable, particularly given the age and condition of much of the buried cable. NOTE: CEI is planning to replace selected substation feeder exit cables

Discussion

In the period 2004-2006, CEI's 4kV circuits experienced approximately 30,000 CI from outages on three-phase cable in conduit (excluding dig-ins). While not all of this is exit cable as such, by far most of it is, and the issue is much the same for other cable in conduit (road crossings, etc.). In 2006, the 30,000 CI arose mainly from 100 outages on 50 circuits. The worst 30 circuits over the period averaged 17,000 CI per year on 30 circuits, including 6 circuits from the Harrington substation, 5 from Lakewood, 4 from Jersey and 3 from Gladstone. While we did not request detailed data on those particular exit cables, we estimate that the typical job of exit cable replacement might involve an average of 1500 feet of cable at a cost of $30 per foot, or $45,000 per circuit. Replacement of the worst 30 circuits would therefore cost $1.35 million. The effectiveness of the replacement might ordinarily be assumed to be almost 100 percent, since the new cable should be less likely to fail, but in reality the effectiveness, as applied to the targeted CI, is dependent on how likely it is that other exit cables, not selected, may fail instead of the ones targeted, thus causing the same level of exit cable customer interruptions.

That is why it is important to use diagnostic equipment to test the exit cable, in order to ensure that only those cables that are prone to failure will be replaced. In fact, using the VLF testing, the cable will fault, requiring at least a repair, i.e., replacement of the faulted section or splice, if not replacement of the whole length.

If it can be assumed that by targeting the worst cable for replacement, 50 percent effectiveness can be achieved, then a reduction of 8,500 CI might be achieved, for a SAIFI impact of .01, at a unit cost of $159 per CI avoided.

A second tier might address the next 30 4kV circuits. In the period 2004-2006, these circuits generated an annual average of 7,000 CI from exit cable faults, and so would afford about 40 percent of the opportunity of the first tier for the same cost, i.e., a reduction of 3,400 CI, for a SAIFI impact of .005, and a unit cost of $397 per CI avoided. Because of the economics, and the existence of other programs that could help CEI achieve its goals, we would not expect the second tier of this program to be implemented.

SI-8	Develop a worst-CEMI program, not necessarily to substantially improve reliability, but to ensure a proper balance with Customer Satisfaction (Key off of Worst Performing Devices Report analyzing all equipment that experiences 2 failures in a month or 3 in a quarter).

Discussion

This program is targeted at improving customer satisfaction by addressing the outliers of performance rather than by affecting the average, hence it is expected to have only minimal impact on SAIFI.

SI-9	Replace failure-prone URD cable to avoid customer complaints and save repair costs (minimal impact on improving overall SAIFI). NOTE: CEI will replace approximately 300,000 feet of URD cable in 2007 and is planning to replace an additional 200,000 feet in 2008.

Discussion

This program is targeted at improving customer satisfaction by addressing the outliers of performance rather than by affecting the average, hence it is expected to have only minimal impact on SAIFI.

SI-10	Integrate the Circuit Health Coordinators with the ESSS Inspection Program to provide an over-inspection role, as well as a coordinator to address high-priority reliability-related inspection deficiencies/exceptions.

Discussion

This recommendation is designed to ensure that the implementation of the Circuit Health Coordinators does not negatively impact the effectiveness of the existing ESSS Inspection Program. As such, it is more important for avoiding SAIFI problems that would otherwise occur than for achieving a specific improvement in SAIFI.

Non-Distribution Circuit Recommendations

Consistent with the Outage History and Cause Analysis (Section 3.0), the Service Interruption Assessment was focused on the programs and processes related to the

Distribution Lines/Circuits. However, CEI still needs to maintain an appropriate amount of attention on the substations and subtransmission lines, as well. Significant improvement was noted in over the past 5 years in both areas, and should continue as CEI remains committed to those measures that contributed to this improvement. Recommended actions SI-11 and SI-12 highlight the importance of maintaining that focus, and document the investments that have been made in 2007 (and are planned for 2008) to continue and/or maintain this improvement:

SI-11	Continue to address the operability of switches on the subtransmission system NOTE: CEI will replace 9 36kV older-style problematic switches in both 2007and 2008. NOTE: CEI is also going to prioritize the need and rebuild, as necessary, additional 36kV circuits.

Discussion

The impact of continuing to replace problem switches will be to offset the long-run deterioration of this equipment. Since this is the primary action related to the improvement in subtransmission SAIFI, continuance of this practice is highly recommended.

SI-12	Continue to replace circuit breakers and relays at the substations. NOTE: CEI will be performing the following projects in 2007: Upgrade 11-13kV Feeder Breakers at 3 distribution stations; Install 5-three-phase reclosers as interim feeder protection; and Replace slow reset CO-5 relays at 5 substations. NOTE: CEI is planning to perform the following projects in 2008: 13kV Feeder Breaker upgrades with SCADA control; Replace additional slow reset CO-5 relays; Replace 2-36kV Feeder Breakers at Northfield Substation; Replace Circuit Switchers at 4 substations NOTE: CEI is also planning to replace substation batteries at 20 substations in 2007 and 10 substations in 2008.

Discussion

The impact of replacing circuit breakers and relays at selected substations will be to offset the long-run deterioration of this equipment. The impact on the next few years, then, is likely to be not significant, but it would accumulate to a significant effect if ignored for five or more years.

6.0 Service Restoration Assessment

6.1 Purpose, Scope, and Approach

The purpose of this section of the report is to explain our analysis of the Company's service restoration process. As noted in our Reliability Assessment Framework (Section 4.0), one element of improved reliability is related to mitigating or eliminating service interruptions ("outages") as presented in Section 5; the second key element is related to the timely and effective restoration of service after an interruption has occurred.

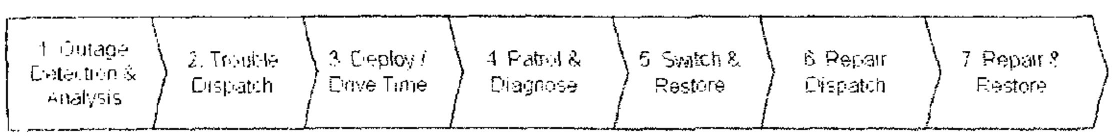
Utilities across the United States are increasingly and appropriately subjected to regulatory and public scrutiny about their service restoration performance, especially in the context of storms and public emergencies (as measured by CAIDI). In many cases, post-storm assessments have been done by third parties at the request of the utility and its regulator. These assessments and specific responses by utilities have resulted in valuable lessons for the industry and the key concepts described below are used to compare CEI's current policies and practices and results.

6.2 Service Restoration Process

The service (or outage) restoration process is perhaps the most complicated operational process at any electric utility. It requires coordination and communication across substantially all key functions of the distribution business and is implemented in a time-critical environment (often in extreme weather conditions and non-standard working hours). It requires an extraordinary focus on safety while key participants are making innumerable real-time decisions to satisfy to the operational, engineering, and customer related demands.

These extreme and complex performance requirements have led utilities to take a highly process-focused approach to managing and monitoring these critical reliability-related activities. While no two utilities implement these processes in precisely the same manner, they all follow a general flow as outlined in Figure 6-1 below:

Figure 6-1
Typical Outage Restoration Process



A summary level definition of these process steps are as follows:

1. Outage Detection & Analysis – This process step begins with the first call, usually from a customer but sometimes from police/fire agencies or the public at large when they see a wire down, street lights out, etc. In more advanced systems they may come from sensing devices. The key activity here is to recognize that multiple calls may have a common root cause and so must be grouped into a 'case' or 'outage', with each outage being the grouping of one or more customers who are electrically 'behind' the same isolating device, be it a fuse, recloser, circuit breaker, substation, bus, or transmission line. While an outage management system may suggest, based on a model of how customers are connected to the system, which customer calls roll up to which common device, ultimately a human must confirm or change that assignment through a process that involves outage analysis. On a clear day, for example,

it is unlikely that customers on two different but nearby taps might call in within fifteen minutes of each other because of two separate outages, so the automated algorithm will typically assume that they are related to a common point of failure upstream of both of them. On a stormy day, however, it is possible that two such outages are distinct. Ultimately, the case will be determined by the crews' onsite observation, but in the meantime a dispatcher or a case analyst working with the dispatcher must make an assignment of calls to cases or outages.

2. Trouble Dispatch – Once the dispatcher has identified a "case" or outage, a troubleshooter can be assigned and sent ("dispatched") to the likely location of the fault, or at least to the location of the isolating device. In fact, as soon as the first call comes in, it may be assumed to be a 'single no-light', i.e., an outage involving only one customer, and a troubleshooter may be assigned to start moving in that direction. As more calls come in and the case is analyzed, the location of the isolating device may change from the premise of the original call to the common isolating device (fuse, recloser, etc.) of the group of calls that make up the case. One of the key issues during this stage of the process is whether a troubleshooter is available, or will be soon, to go to the call, and if not, whether some other first response resource can be mobilized to fulfill the role. This will depend, of course, on the dispatcher's sense of whether the outage is large enough or would be delayed long enough to warrant mobilization of a different resource. In the worst case, e.g., in a major storm, outages may queue up at this stage of the process and await the next available resource, all while time passes and customer minutes of interruption accumulate.

3. Deploy / Drive Time – Inevitably, one step of the process must be deploying the troubleshooter to the location. Depending on the size of the territory, the time of day, and where available resources are currently deployed, the travel time may be short or long. In addition, one may group into this category the time it takes to mobilize a resource, i.e., if the dispatcher has decided to call out a resource from off duty, the case may be considered as assigned (and so no longer awaiting dispatch) but the troubleshooter to which it is assigned is not actually en route to the location but is still being mobilized.

4. Patrol & Diagnose – Once the troubleshooter arrives at the location of the isolating device, and maybe even while on the way, depending on the optimal route of travel, the troubleshooter will look for evidence of a fault – broken limbs or fallen trees, an auto accident or dig-in, etc. This is called patrolling and it has two functions – one is for public safety, to be sure that there is no wire down anywhere that could make it unsafe to re-energize the line and the other is to find the fault that caused the isolating device to operate. Many times, the offending root cause will have cleared itself, as in when a branch singes its leaves to the point that they no longer can make contact with the line, or when an animal is no longer in a position to bridge the gap between conductor and ground (or another conductor), etc. In such instances, the troubleshooter will be able to re-energize the line (replace the fuse, re-set the recloser or breaker) without experiencing another fault, but the line should be patrolled first to ensure that such an action can be taken safely.

5. Switch & Restore – If the troubleshooter finds the location of the fault-causing damage, and it is clear that it is a permanent fault that will not be cleared until

the damage to facilities is repaired, then the next action is to look for ways to accomplish partial restoration, i.e., restoring at least some, and hopefully most, of the customers. This is done by first isolating the faulted section of line and then re-energizing the un-faulted sections. Isolating the faulted section may be done by operating two disconnect switches on the line – which are placed at various points along the line for just such purposes, or by 'cutting in the clear', i.e., cutting conductor on each side of the faulted section, with the intention of splicing the line back once the repair is done. In some cases, if the permanent repair is straightforward and can be accomplished quickly, or if the number of customers affected is small and not easily restored by other means, then this switch and restore step will be skipped and the process moves straight to repair and restore.

6. Repair Dispatch – Once the faulted section is isolated, it is usually necessary to get a full line crew out to do the permanent repair. A lone troubleshooter can only do minor line repair. The process of getting a line crew requires going through the dispatch function for that resource, which may be another person. Line crews typically scheduled to perform new construction, road moves, or planned replacement/upgrade work, and are likely to be busy with another job when they are called out to do restoration repair work. The dispatcher for those resources makes the judgment call about which crew can most easily be interrupted to be sent to do the outage repair work. Note that strictly speaking, there is another step in the process at this point, which is travel time for the repair crew, but this is usually grouped into the repair time, because the repair time is likely to be significant (compared to the relatively quick step of switching and restoration).
7. Repair & Restore – Once the repair crew arrives at the site of the damage, the permanent repair can be made and the last group of customers restored. Depending on the extent of the damage, this can be a matter of many hours.

Within the context of this process, there are certainly opportunities to isolate each step and identify opportunities for improving service restoration (i.e. reduce customer minutes of interruption). And the company should, as a matter of course, perform a detailed challenge of each process step to identify these opportunities and incorporate any findings into its overall reliability improvement plan. For the purpose of this assessment, we will take a cross-sectional view of these steps by first, looking at service restoration performance from an overall perspective; and then, assess the company's performance in three domains: Mobilization, Work Flow and Communication.

6.3 Service Restoration Performance Overview

Before addressing the company's practices, processes, and performance with respect to service restoration, it is appropriate to review the company's CAIDI performance over the past 5 years to assess the overall trend towards achieving the 2009 target of 95.0. Figure 6-2 shows a stepped improvement in CAIDI since the 2002/2003 period, as CEI closed the gap by 50 percent (to approximately 125.0 minutes). This amount of improvement reflects an obvious management focus on improving practices and processes around service restoration. Equally impressive (and daunting), is the amount of improvement still required to reach (and sustain) the 2009 target.

Figure 6-2
CEI CAIDI Performance – Non-Storm without Transmission

	2002	2003	2004	2005	2006
Outages	7,533	6,759	6,615	8,661	8,246
CMI	110,796,914	156,335,383	111,309,573	141,040,088	112,382,533
Customers Interrupted	717,517	932,418	846,068	1,234,999	875,992
CAIDI	154.42	167.67	131.57	114.20	128.29

Consistent with the approach developed in Section 3.0, the main focus of this assessment (in terms of identifying opportunities for leveraged improvement) will be with the distribution feeders (with particular emphasis on the backbone). Therefore, a view of CAIDI performance from a district perspective is appropriate; looking primarily at distribution line CAIDI (i.e. less substation and subtransmission CAIDI).

Figure 6-3
CEI Distribution Line CAIDI Performance

Reported District	2002	2003	2004	2005	2006
Ashtabula	140.84	254.06	171.74	150.01	191.84
Brooklyn	212.73	211.76	180.39	175.48	136.74
Concord	147.86	206.78	187.05	170.43	121.35
Euclid					
Mayfield	173.98	177.55	181.18	164.43	143.55
Miles	183.65	202.57	183.61	155.31	170.00
Solon	213.10	255.54	172.28	123.62	134.79
Strongsville	171.14	174.50	188.14	163.01	150.04
West Lake	156.30	173.65	148.17	200.38	153.70
Total	171.98	208.41	176.66	166.83	148.65

NOTE: Euclid represents a new line district started just prior to 2007.

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 (the West Lake and Miles line districts have oscillated over the five year period, with negligible, if any improvement). Ashtabula represents almost half of the territory. CEI is in the process of establishing another line district (Claridon Twp) (planned in-service date of 2009) to help alleviate the challenges inherent to such a large area and established the Euclid line district in 2007 to alleviate some of the challenges associated with the Miles line district.

Viewing Figure 6-4, there is no other obvious correlation between the CAIDI performance trend from 2002 through 2006 and the demographics defining each district. This would suggest that the solution, therefore, lies in further improving the overall processes and practices, much of which is already in progress (as indicated in the performance improvement to date).

Figure 6-4
CEI District Demographic Information

District	Customers		Circuits				
	Number	PCNT	CKT Miles	PCNT	OH Miles	UG Miles	PCNT OH
Ashtabula	62,136	8%	1,932	16%	1,638	294	85%
Brooklyn	135,553	18%	1,436	12%	981	456	68%
Concord	67,618	9%	1,953	16%	1,028	926	53%
Euclid	53,302	7%	530	4%	382	147	72%
Mayfield	95,667	13%	1,275	11%	947	329	74%
Miles	121,680	16%	1,318	11%	784	534	60%
Solon	28,491	4%	920	8%	382	530	42%
Strongsville	104,473	14%	1,407	12%	664	743	47%
Westlake	78,106	11%	1,179	10%	566	612	48%
TOTAL	**747,026**		**11,949**		**7,371**	**4,578**	**62%**

6.4 Service Restoration Performance Assessment

In assessing the company's performance in service restoration, this assessment will compare CEI's practices and processes against industry "leading" practices from three related perspectives:

- Mobilization (with an emphasis on being proactive in terms of planning and establishing contingencies),
- Workflow (focusing on partial restoration and follow through for permanent restoration), and
- Communication (both externally with the customers and internally in terms of timely reporting of customer restoration).

6.4.1 Mobilization

Regarding mobilization, some of the major insights of leading utilities in this area involve recognizing the considerable benefit that can accrue to early mobilization. Although the benefit of early and effective mobilization must be weighed against the cost of mobilizing resources for a 'false alarm' (i.e., a storm that either does not hit as forecast or does less damage than that forecasted), the pendulum is swinging toward ensuring that enough resources are at hand early in the storm because of the importance of getting the mainline feeders back up quickly.

Until the feeders are returned to service, dispatchers are operating "in the dark" with incomplete information. With feeders down it is difficult to know which taps have also suffered damage. Based on the dynamics around a 'nested outage', the only ways to prevent extended restoration times after a major storm are:

- Conducting field-based assessments
- Initiating special action by the dispatcher
- Prompting customers with IVR to confirm when their service is restored

The remedy is a sufficient complement of feeder troubleshooting and repair crews early in the storm. The alternative, or more appropriately a complementary activity, is to have sufficient damage assessors deployed to the affected areas and find evidence of damage on dead lines. This will only be partially successful, since in some cases the trees have knocked down poles and/or line and it will be obvious; but in other cases the fault is less apparent and will require electrical connectivity to fully isolate and detect the fault.

Early mobilization itself is dependent on two key activities: 1.) weather forecasting that can be translated into resource requirements, and 2.) the prearrangement of additional resources available on a contingent basis. Weather and resource forecasting tends to be well developed for hurricanes but it is often not very well developed for smaller storms, with heavy dependence on dispatcher experience. The number of variables involved in accurately forecasting the impact of a given storm can easily overwhelm the experience-based forecasting capability of dispatchers and/or storm managers, leading them to fall into a 'wait and see what the damage is' approach, which can take far too long in the critical early stages of post-storm restoration. The industry is working on developing better tools to assist in such instances.

The second element - being able to garner sufficient resources quickly - involves three different layers of resource support:

- The company's own resources, both repair crews and also second-job resources for wire watching, damage assessment, and logistical support,
- The company's contractors and those of other companies that can spare them, and
- Mutual assistance resources (again, mainly repair crews but in some cases support personnel as well) from other utilities that can reach the affected area in a timely manner.

The first layer, the company's own resources, would seem to be straightforward. However, it can be complicated by work rules and the company's ability to call out resources from home or other assignments. Also, the second-job capability that support staff can provide can only be effective if they are trained and drilled in how to assist properly in the effort.

The second and third layers depend on good relationships and communication with contractors and nearby utilities. Such relationships must be worked out in advance in some detail. All utilities, of course, have some experience at using mutual assistance, but even within that body of experience it is recognized that some do it better than others, with the right processes to enable foreign crews to be effective in one's own restoration efforts. Some find it necessary to break up their own crews and assign them one each to the foreign crews to allow them to read maps, draw materials, record restoration, etc. Another well-known factor is that companies which are currently using contractors for construction or maintenance may find it easier to tap the resources of the contracting company in an emergency.

In general, CEI complies with these concepts, particularly using servicemen (line leader shift) and support staff (ranging from simple logistics to performing damage assessments), and establishing clear policies/procedures to govern the transition of shifts. There are, however, a number of areas where the company can further reduce customer minutes of interruption; these topics are explored in the following subsections.

Storm Pre-Mobilization

Pre-mobilization with respect to storms offers a potentially high leverage point in eliminating customer minutes of interruption. Figures 6-5 and 6-6 (previously presented in Section 3.0), provide a historical perspective of the correlation of effective wind speed, outages and average outage duration.

Figure 6-5
CEI Storm Model

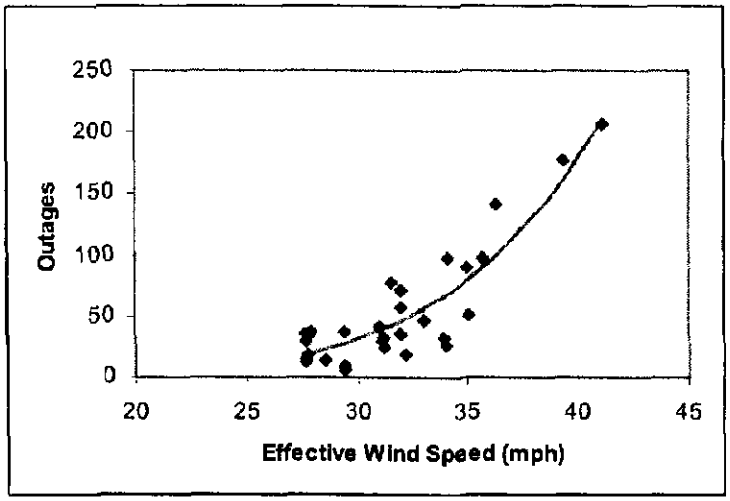
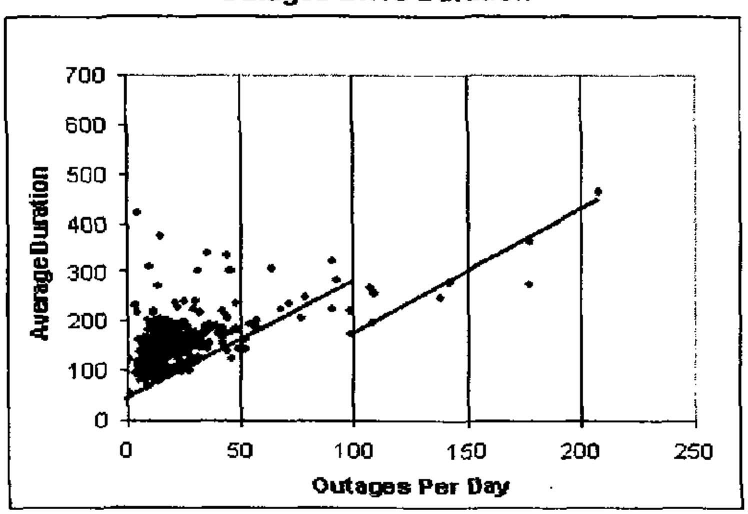


Figure 6-6
Outages Drive Duration



As one would expect, Figure 6-5 shows that effective wind speed certainly has had an impact on the number of outages that have occurred during any one storm event (in fact, the relationship has been exponential with a rapid increase in the number of outages as effective wind speeds have exceeded 30-35 miles per hour). Further, the number of outages has had a definite effect on average outage duration, with an apparent stepped improvement at 100 outages per day (most likely due to a change in system restoration staffing in anticipation of a storm), and at about the same point that effective wind speed hits the 30-35 miles per hour threshold. Similar correlations are likely to exist with other weather-related variables (e.g. heat storms, lightning).

Given these interrelationships, CEI could benefit by integrating all of these factors into a common methodology to introduce empirical data into the decision around pre-mobilizing staff (in anticipation of a storm); not in place of the intuitive and experiential approach that is already working, but as an enhancement to it. There is obviously a cost-benefit relationship that needs to be explored (the cost of pre-mobilization against the anticipated reduction in average outage duration).

CEI Energy Delivery Management would certainly benefit from better understanding the predicted correlation of key weather factors to number of outages per day and the level of incremental staffing necessary to further reduce total customer minutes of interruption.

First Responder Program

CEI has implemented a program whereby certain employees equipped with pagers are put into a database that matches the employees' typical work locations (and home location) with the nearest substations. When the dispatcher gets an alarm that indicates an outage (or warning) condition at one of those substations, the dispatcher can page all those who are matched to that substation with a request that they check with the dispatcher and, if needed, go immediately to the substation to observe the situation.

This program effectively expands the substation troubleshooter staffing by providing "extra eyes and ears" (and, with the proper training, helping hands as well) in those critical situations in which a portion of the substation, e.g., an entire transformer bank feeding many circuits, is either de-energized or alarmed.

It is worth noting that the typical SCADA at a substation involves a limited number of alarms that while informative may not be conclusive in what they tell about the situation. For this reason, it is very useful to have whoever is nearest to the substation get there as soon as possible – even if that person might not be qualified to do switching or some other aspect of restoration or prevention.

If the responding staff member is trained and qualified, and the work rules allow it, the first responder may be able to initiate action that restores customers. Clearly, substation outages can involve large numbers of customers – even more than lockouts of a single feeder, so anything that can be done to reduce the restoration time for such outages could have an impact on overall CAIDI.

In our interviews, we heard substation supervisors endorse the value of the First Responder program (even encouraging more effective participation). We similarly feel that reinforcement of this program can only help CEI's CAIDI while having minimal negative impact, if any, on costs or productivity of the workers involved. This is a First Energy practice that many others in the industry would do well to emulate.

Call Outs

A key factor in achieving improvement in CAIDI is improving the time it takes to mobilize a crew that must be called out from being off duty. All utilities struggle with this challenge and various changes in processes, work rules, and technology have been utilized to address it, including such things as using more sophisticated paging or cell phone systems to maximize response, changing work rules that require that callout be done in order of seniority, as well as how and when the utility is allowed to move down the list and the minimum block of time for which a callout is credited, and even allowing crews to drive trucks to and from home after duty.

CEI's response rates presented in Figures 6-7 and 6-8 are typical for the industry with the overhead lines and substation response rates at 57 and 53 percent, respectively. Top quartile performance is in the range of 70-75 percent. However, the impact on overall CAIDI in closing a 13 to 17 percent gap would be minor and should not be a major focal point in achieving the 2009 targets. That being said, call-out response is certainly a measure of organizational alignment around the issue, and should be used more as a barometer of CEI's effectiveness in establishing this alignment, than as a point for focused improvement.

Figure 6-7
Overhead Lines Call-Out Response

Month	PAGER CREW					NON-PAGER CREW				
	Total Calls Made	Yes	No	No Answer	PCNT	Total Calls Made	Yes	No	No Answer	PCNT
JAN	26	21	2	3	81%	245	131	70	44	53%
FEB	49	44	4	1	90%	379	149	68	162	39%
MAR	14	11	1	2	79%	132	95	16	21	72%
APR	39	37	0	2	95%	291	146	104	41	50%
MAY	43	43	0	0	100%	374	204	145	25	55%
JUN	35	34	0	1	97%	273	169	60	44	62%
TOTAL	206	190	7	9	92%	1694	894	463	337	53%

TOTAL CALLS	1900
YES	1084
NO	470
NO ANSWER	346
PERCENT	57%

Figure 6-8
Substation Call-Out Response

Area	Calls	Responded	PCNT
East	335	166	50%
West	80	56	70%
TOTAL	415	222	53%

Alternate Shift

For the last five years utilities have been experimenting with the use of an alternate shift to better match the availability of crews with the need for repair work in minor storms. The standard utility shift is related to the standard 'day shift' in all of industry, with a shift toward the morning as is typical in many construction-related industries (the typical utility day shift is 7AM to 3PM or 7:30AM to 3:30PM).

Statistically, it can be shown that particularly in the non-winter seasons thunderstorms that develop from normal diurnal convective activity are more likely to occur in the mid- to late-afternoon or early evening. Therefore, in many instances the storms hit just as utility construction crews have quit for the day. When the storms can be anticipated, the utility can make an effort to 'hold over' some crews from the day shift (on an overtime basis) and this is another initiative in itself on which we will comment below. Also, crews can be 'called out' by telephoning or paging them with a message to contact the dispatcher for an extra duty. A less costly and more certain measure is to arrange for some of the crews to work an alternate shift. Of course, the 'evening shift' that some of the troubleshooters work is well suited to handle such storms, but if the damage involves significant line work, then full overhead line crews will be needed to make the repairs.

It is possible to have construction crews on an evening shift, but it is not ideal because the need for them does not typically extend to the end of such a shift, e.g., 11PM, and more importantly such a shift, on a regular, daily basis, tends to conflict with worker productivity, visibility, safety, and customer satisfaction (due to noise and intrusive activity in the evening hours).

The alternative that many utilities have developed is to have a shift that begins around 11AM or noon and extends to 7PM or 8PM. Particularly if this is used in the daylight savings period, the concerns about working at night are allayed and the shift does not seem as unnatural, and may even be preferable to some workers. The typical practice is to have only a handful of crews switch to this shift, because for various reasons the standard construction shift remains the ideal for most. However, the shift of even a few crews can noticeably improve the ability to respond to late-afternoon storms as shown in Figure 6-9 below.

Figure 6-9
Outage Duration by Hour of the Day

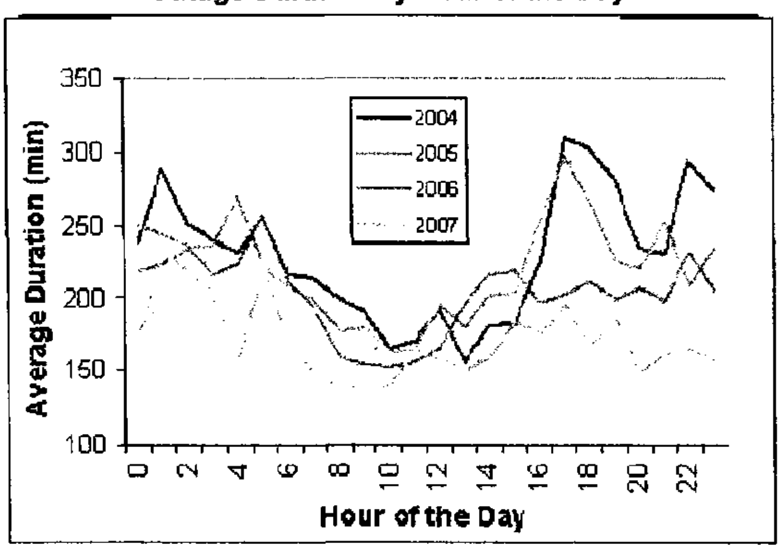


Figure 6-9 above shows that the use of alternate shift was first introduced in 2004, but used rather intermittently. As CEI approached 2006, this practice became more wide-spread, the results of which are evident on the profile of outage duration by hour of the day. The 2006 and 2007 (year-to-date) profiles show no real differentiation during the 4PM to 8PM time frames (in contrast to the marked improvement over 2004 and 2005). These trends (as well as those experienced by similarly configured utilities) point to the need for the Company to remain committed to this leading industry practice.

6.4.2 Workflow

In terms of workflow, our assessment will focus on methods of returning as many customers as possible to service during the initial stages of the switching and restoration phase of the outage restoration process. There are some issues in the area of dispatching, not from a practices perspective, but because of the recent influx of inexperienced dispatchers and the challenge of retaining staff in these key positions once they have been trained (addressed in Section 7.0).

Partial Restoration

Partial restoration refers to the practice of switching and even cutting around faulted sections of a line to be able to restore at least part of the customers early on, leaving a smaller group of customers to have to wait until final repairs are made. This practice has long been a part of utility outage restoration efforts and it has also long been resisted. To be fair, it is appropriate to resist using the method when a final repair could be made relatively quickly and it is always a judgment call as to whether it is better to use the available resources to complete the final repair or to divert them temporarily to make other partial restorations.

Utilities regularly report that line crews prefer to do the final repair and try to convince the dispatcher that they will be able to do it quickly. The risk is that unforeseen delays may cause a large number of customers to remain unconnected when partial restoration might have been done expeditiously for a large majority of the customers.

CEI has confirmed that this typical tension does exist and has committed itself to reinforce its position on partial restoration. We would emphasize that this is particularly relevant when restoring feeder backbones:

- When the backbone is out, all of the customers on that feeder are out, which on the 13kV circuits is often over 1,000 customers.
- Until the feeder backbone is restored, it is generally not possible to discover, except by detailed patrol, that additional locations or taps require repair in order to effect restoration.
- Except in the most rural areas, the system is designed to allow feeder backbones to be 'back-fed' through normally open ties to other feeders. This allows the utility to isolate the faulted part of the feeder and close the appropriate ties to re-energize a large number of customers on the circuit.

The system, in fact, is designed with redundant capacity for precisely the purpose of handling contingent capacity for partial restoration. In many cases the 'partial' restoration can be almost a complete restoration (e.g. in instances where only a single span or a few spans need be isolated in order to clear the fault, the rest of the feeder can be restored as fast as it takes to throw disconnect switches or even physically cut the conductor to isolate the fault and then throw the tie switches to restore). This is in part why installation of more automatic reclosers is recommended – they rapidly isolate a faulted zone and re-energize the rest of the feeder, allowing the remaining restoration effort to concentrate on a zone that is more compact, significantly decreasing the miles required to drive to close each normally open tie.

Therefore, we recommend that CEI continue to reinforce the practice of partial restoration, especially 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.

Split and Hit

Another method of partial restoration is termed 'split and hit'. This is normally applied to underground residential distribution (URD) lines, but could conceivably be used on overhead lines where the density of tree cover or dark of night prevents the troubleshooter from being able to easily locate the fault (though in the latter case extra precaution is required to ensure public safety when re-energizing the line). The challenge being addressed with this approach revolves around locating the faulted section of cable. This applies typically among the many sections of underground primary that extend from the riser through each of the pad-mounted transformers to the normally open point of the typical URD half-loop. Once the faulted section is located, the pad-mounts on each end of only that section are opened, the elbows are disconnected and parked, and the pad-mount at the normally open point is opened, its elbows un-parked and connected, thus 'back-feeding' the half-loop up to the faulted section.

The blown riser can then be replaced, re-energizing the front part of the half-loop. At that point, all customers are restored, and will remain so until the cable faults in a different section. This is comparable, in concept, to 'switching around' an overhead faulted section, i.e., a workaround that isolates the faulted section and restores service at both ends of the faulted section through switching. In the meantime, it is important to repair or replace the faulted section of cable in a reasonable time, so that it can be used in a similar fashion to complete a half-loop should another section fail.

At times it is appropriate to call out a special underground crew, supplied with test equipment and trained to locate the faulted section. This approach will likely cause some delay in effecting the restoration. The more expeditious alternative is to have the lone troubleshooter, the first to arrive at the scene, use the 'split and hit' method:

- The troubleshooter should go to a pad-mount halfway between the riser and the normally open point on the half-loop (in order to 'split' the half-loop into a quarter-loop). Since the riser fuse is blown, this transformer will be de-energized.
- The troubleshooter should then disconnect the cable elbow on the blown riser side, then go back to the riser pole and, using a hot stick, replace the fuse ('hitting' the quarter-loop by re-energizing it).
- If the faulted section of cable happens to be on the re-energized side, the fuse will blow immediately (which is why the troubleshooter must take appropriate precautions such as looking away, etc. – this is no different than when the same is done on an overhead tap that has been patrolled and found to have no obvious faults).
- If the fuse holds, power has been restored to that quarter-loop, and even if it blows, the troubleshooter can then restore the other quarter-loop by going back to the split point, disconnecting the faulted side, and back-feeding the un-faulted side from the normally open point, since cable faults almost always occur on only one section of cable in a half-loop.

- At this point, the troubleshooter will apply the same method to the remaining faulted quarter-section, restoring even more customers, or, if there are other outages that need troubleshooter attention, and the number of customers out on this tap is now relatively small, the troubleshooter will call for the test crew to complete the job on the remaining quarter-section.

In the meantime, the number of customers interrupted has been cut in half, often in less time than it would take for the underground crew to be mobilized and travel to the site. FirstEnergy has used the split and hit method effectively for years in other regions. It is an industry leading practice and we recommend that CEI continue its use.

6.4.3 Communication

Regarding communications, a recurrent theme in post-storm assessments is the need to do a better job of keeping everyone informed about the current state of the restoration efforts and to establish a culture of continuous improvement through forums geared to constructive sharing of experiences and circumstances, both positive and negative. This includes customers, employees, contractors, foreign crews, communities, emergency agencies, regulators, media, and other public officials. Moreover, the best way for people to get information is to know in advance what information is available and where. Through advanced planning and drills, communities can come to better understand the role of various different community functions in restoration. In a phrase, "plan the work, work the plan," is the approach that will instill the most confidence and dispel the confusion and competition for resources that comes from a more ad hoc approach.

Implementing all of these leading practices requires an organizational focus on achieving desired performance levels in storms through planning and follow-up on process changes and learning what works best. It is no longer acceptable to merely claim that infrequent storms are extraordinary events that cannot be measured in terms of performance. On the contrary, the increasing demands and expectations of the public for community continuity even in the face of emergencies requires a planned approach to what might seem to be an unforeseeable event.

In assessing CEI's performance in the area of communication, the following observations and recommendations are provided:

- CEI has devoted a portion of their website to provide customers with timely emergency and storm restoration information. Our view is that this website is well-designed and implemented, and serves as an effective supplement to the more traditional communication methods.
- CEI's IVR is effective in managing the customer interaction and is cited as one of the factors in their experienced improvement in customer satisfaction.
- Recognizing that the "moment of truth" occurs at the scene of action (and often occurs between the servicemen/line crews and the customer(s)), CEI provides training on how to properly interact with the customer.
- CEI as instituted the 4-Hour Outage Review Process to address the causes, remedies, and "lessons learned" in outages that exceed 4 hours in duration. This appears to be highly effective in that it deals objectively with the issues and keeps the focus on shortening outage duration.

- Following the lead of other FirstEnergy companies, CEI has instituted an Outage Page, ensuring a sense of urgency and supervisory awareness of all outages involving feeder lockouts, and those affecting more than 100 customers (the notifications occur at the start of an outage event).
- In an effort to improve the coordination and communication between Regional Dispatch and the field, CEI has instituted a cross-familiarization training program between the dispatchers and the servicemen. The dispatchers receive field familiarization training and the servicemen receive similar training in the RDO/Call Center.
- The Monthly Reliability Meeting is among the best we have experienced, in terms of relevance, clarity, and action-orientation. The annual goals are articulated, progress against them assessed, and specific challenges from the previous month vetted; all of this information is presented with a focus on supporting a continuous learning environment.

6.5 Summary of Recommendations

The following specific recommendations are submitted recognizing that many of the suggested improvement initiatives are already integrated into the company's practices and processes (as evidenced by CEI's improvement over the past five years). Within each practice and process there is the opportunity to apply some fine tuning to further reduce customer minutes of interruption.

SR-1	Systematize the process of determining when to mobilize staff in anticipation of a storm.

<u>Discussion</u>

The company effectively applies experience, intuition and weather information to proactively apply supplemental resources prior to storms. Figure 6-6 shows that the impact of this combined experiential and intuitive approach equates to mobilizing for storms that lead to over 100 outages. The opportunity involves "sharpening the pencil" a bit, and determining where the cost-benefit trade-off occurs by applying the correlation of number of outages and key weather variables into the analysis in a more quantifiable and predictive manner.

From Figure 6-6 it is evident that mobilizing for storms can save an average of approximately 100 minutes per outage. It is also clear that there are approximately ten days per year that have outages per day in the range of 50 to 100, say an average of 75. These ten storms then generate 750 outages per year. CEI's typical average number of customers interrupted per outage is approximately 100, so these medium-outage days represent 75,000 customer interruptions. Now, a 100-minute saving on each would generate a potential savings of approximately 7,500,000 CMI (customer minutes of interruption, the numerator of SAIDI and CAIDI). If CEI is able to meet its SAIFI target of 1.0, a savings of 7,500,000 CMI would have a favorable CAIDI impact of 10.0 minutes. As a conservative estimate, we believe CEI can achieve 60 percent, or 6.0 minutes of CAIDI improvement from this method.

The cost of the additional mobilization could be estimated in terms of having approximately 45 additional resources available for a few hours in each of the ten storms (roughly, one 2-person line crew for each of the 9 shops, 1 hazard person for each, and a troubleshooter/switcher pair for each). Of course, if the timing is right, there would be no incremental cost for these resources, since they were needed anyway, so the real cost is when they are mobilized unnecessarily. If this were half the time, say 3 hours on average, we might expect a cost of approximately $10,000 per storm, or $100,000 per year. The unit cost can be viewed in terms of 100 CMI (approximately the duration of a typical interruption for one customer) as $2.22 per 100 CMI. Clearly, this is a program that CEI should heartily endorse.

A 'second tier' of implementation of SR-1 would be to apply the same logic to the larger storms as well, i.e., the storms which, though still minor enough to not be excludable, involve 100 to 200 outages per day. From Figure 6-6 it is clear that CEI already 'shifts gears' when this level of storm is experienced, but the sheer volume of outages on those days still leaves the average duration above 200 minutes (yet better, by 100 minutes, than what it would be without a changed paradigm). If the timing and level of mobilization for the larger (yet still not excludable) storms could be increased still further, we believe that a further improvement in CAIDI for those days could be achieved, with a quite reasonable estimate being an average of 50 minutes, e.g., reducing a 300-minute CAIDI to 250 minutes. If this could be done for the approximately 10 days that fall into the category of 100 to 200 outages per day, for which the average number of customers interrupted is 10,000 to 20,000, and the average CMI is 2 to 8 million CMI for each storm, the effort could achieve an additional reduction of 7,500,000 CMI, for an additional CAIDI impact of 10.0 minutes. We believe that a conservative estimate of what CEI might be able to achieve might be 5 minutes. The cost of this additional mobilization would probably be comparable to that of the first tier, because we are only looking to improve the average CAIDI in each storm by 50 minutes.

SR-2	Fully implement partial restoration ("hit and run" for overhead lines; "split and hit" for URD cable) when initially servicing customer outages.

Discussion

These methods require continual reinforcement as there is a natural tendency on the part of linemen (and with every good intention) to want to restore all customers in a given area to service as soon as possible. Consistent with the philosophy of focusing on the feeder backbone, these approaches focus on reducing the total number of customer interruption minutes by restoring as many customers as possible as soon as possible.

In terms of quantifying the potential impact of partial restoration on customer minutes of interruption, one approach would be to suggest that in the typical backbone outage, there are approximately 300 customers interrupted (500 for a lockout, 250 for a backbone outage past the first zone) for approximately 120 minutes, and that through partial restoration 200 of these might be restored in two-thirds the normal time, and the rest in 150 percent of the normal time. This would imply that the outage would accumulate 30,000 CMI instead of 36,000 CMI, for a reduction of 6,000 CMI per outage. If this could be done for half of the 2000 backbone outages that typically occur, the savings would be 6,000,000 CMI, or a favorable CAIDI impact of 8 minutes.

The cost involves having enough troubleshooters, switchers (substation mechanics), and experienced dispatchers to organize and carry out the switching (and perhaps some cutting) involved in partial restoration. The incremental cost of three additional full-time troubleshooters and three additional switchers, for example, would be approximately

$0.5 million, which, if it were adequate to achieve the effect, would represent a unit cost of $16.66 per 100 CMI.

Partial restoration is a practice that has been embraced as an accepted practice within CEI for quite a while. However, our sense during the interviews is that CEI is not achieving the full potential that this opportunity presents; in fact, our estimate is that they are achieving 50 percent of the CMI savings (3,000,000 CMI). That would equate to an opportunity to improve CAIDI by 4 minutes at a cost of $125,000.

SR-3	Fully implement use of the alternate shift (based on documented evidence of reduced outage durations at the critical transition time between normal shifts)

Discussion

There is likely to be ongoing pressure to reconsider the alternate shift (particularly in future discussions with the bargaining unit). The company should continue to evaluate the impact of the alternate shift (using a similar methodology applied in this assessment) to demonstrate its effectiveness and justify continuing the approach. If anything, the analysis should look for opportunities to expand this approach (district by district and at differing time frames).

The impact on CAIDI of having the alternate shift may be gauged by the difference noted above in the average duration by time of day (although this may also be due in part to better mobilization for late-afternoon storms). The difference is approximately100 minutes for three hours (5-7PM), and those three hours on average comprise 20 percent of the CMI for the year, so one could estimate a favorable CAIDI impact of 20 minutes (part of which may be attributable, as we suggested, to other initiatives as well). CEI is already doing this (and has likely captured the majority of this CAIDI benefit within their 2006 numbers), but our sense from the interviews is that its implementation has only recently been applied across all of the districts. We believe this will appear in future years as an additional 2 minutes (10 percent) of CAIDI improvement.

In addition, CEI plans to provide additional supervision to the crews that work on the nights and weekends. It is believed that this additional supervision will result in a marked improvement in CAIDI for outages that occur during those times. In 2006, the CAIDI for the hours outside of the main shift was 30 minutes higher than for the main shift. Even a 10 percent improvement in that gap would yield 3 minutes of improvement for those outages, which make up more than 60 percent of all customer interruptions. Hence, we estimate an additional 2 minutes of improvement in overall CAIDI due to this effort, which we group under this recommendation as being similar to the alternate shift.

SR-4	Continue the recruiting and training of new dispatchers (in advance of the anticipated wave of retirees) and consider ways to make the position more attractive to the more traditional source of supply (e.g. experienced linemen).

Discussion

Section 7.0 addresses the near-term shortfall of experienced dispatchers in the wake of an aging staff. During the interviews, it became apparent that the most obvious source of supply (experienced linemen) is not vying for the position. Apparently, the economics combined with the high-pressure nature of the job serve as a deterrent to what would appear to be an optimal source of supply. Otherwise, the company is likely to experience some impact to customer minutes as the lesser-experienced dispatchers (even though properly supervised) provide direction to the field in basic switching and restoration activities.

As noted above in SR-2, the training of dispatchers can have an impact on the success of partial restoration, since all switching must be coordinated through dispatch.

SR-5	Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007)

Discussion

Clearly, one of the key factors in achieving faster restoration is reducing the drive time between jobs (or between the current location of the crews and their next job). Recognizing this, CEI opened a new line shop in Euclid to relieve the travel time from Miles and Mayfield. The proposed new shop in Claridon Township would provide a much-needed location in the southern part of Concord and Ashtabula districts (and even to some extent the eastern part of Solon district). It is not unreasonable to assume that these new locations will reduce travel time on many jobs by a half-hour or more. Weighting such jobs in with the total time spent on all jobs, we estimate a 5 minute improvement in CAIDI for the eastern districts, which themselves make up slightly more than half of all CMI. This in turn can be expected to have a favorable CAIDI impact of 2.5 minutes. However, since this service center is not expected to open until the end of 2009, its impact on CAIDI in 2009 is nil.

The opening of the Euclid district in 2007, however, may be expected to have a similar, though lesser impact on the future years, including 2008 and 2009. Because the distances involved are much shorter, we estimate only a 1.0 minute improvement in CAIDI from this initiative.

SR-6	Reevaluate level of staffing with respect to outage response

Discussion

The current level of staffing appears adequate in terms of overall performance with respect to service restoration. However, as CEI implements the recommendations of this assessment, there are a number of items that may change the dynamics; namely:

- Increased sectionalizing, while improving SAIFI, will likely have a negative impact on CAIDI.
- Fewer interruptions within an outage could have the same impact as an increase in staff (i.e. lack of demand equates to added capacity).
- Added line districts that will decrease travel time and provide the potential for more efficiency among the staff.
- An accelerated staffing plan that will create a temporary increase in staff to be applied to storm restoration activities (as appropriate).

The purpose of this recommendation is to draw CEI management attention to the fact that some of the variables and assumptions that tend to drive service restoration performance have changed (the impacts of which are somewhat indeterminate); and it would be prudent to keep a close eye on the key performance indicators to proactively make adjustments should they be deemed appropriate.

SI-1 to SI-7	Impact of CI Reduction on CMI

Discussion

In addition to the improvements in CAIDI noted above, which are all due to implementation of recommendations SR1-6, we want to acknowledge that the implementation of the SAIFI-related recommendations will have a favorable side benefit of improving CAIDI because of the reduction in outages caused by vegetation, lightning, and pole-top equipment failures. The combined effect of the outage-reducing initiatives can be expected to eliminate more than 200 outages each year, or about .55 per day, which, based on the slope of the lines in Figure 6-6, can be expected to reduce the average CAIDI by a little over 1 minute. In addition, the sectionalizing can be expected to reduce patrol time significantly on backbone outages, for which the average CAIDI was 115 minutes in 2006. It is estimated that patrol time is almost one quarter of the total CAIDI for such jobs, and that sectionalizing could cut it in half, eliminating 14 minutes from CAIDI for those outages, and therefore 10 minutes from overall CAIDI. Since, however, the sectionalizing will only be done to a select group of approximately 200 circuits; we would estimate that the improved CAIDI from sectionalizing would amount to 4 minutes of improvement to total CAIDI. Therefore, the impact on CAIDI from the various SAIFI improvement initiatives total 5 minutes.

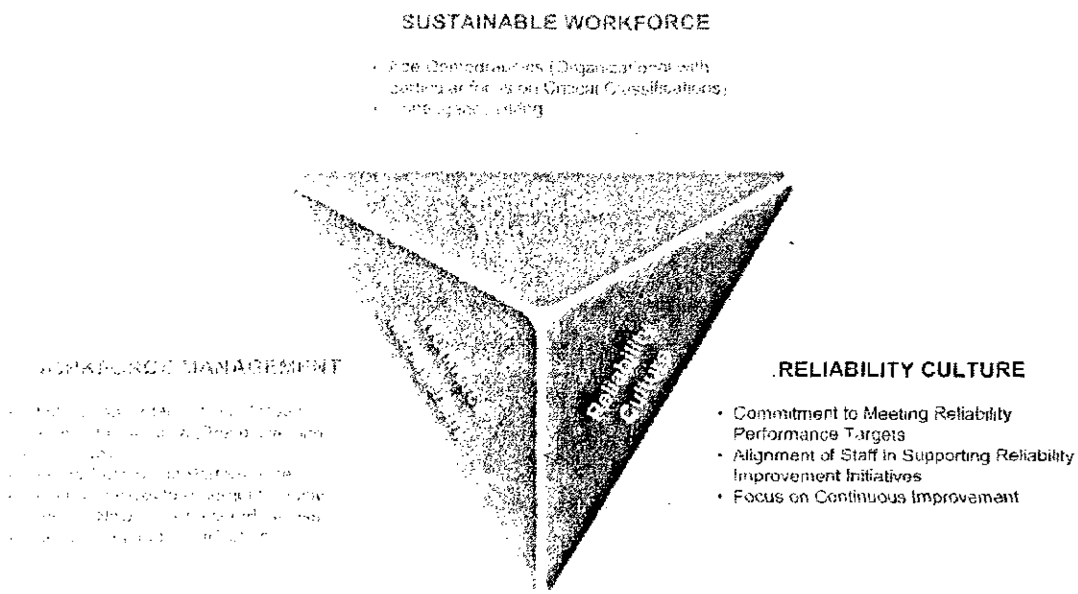
7.0 Organization and Staffing Assessment

7.1 Purpose, Scope, and Approach

The purpose of this section is to analyze CEI's organizational structure and staffing with a perspective on how these elements of the Company affect electric system reliability and offer the potential to sustain improvement in reliability. Our analysis is not a staffing study per se (e.g. it is not designed to be a comprehensive work level or span-of-control analysis); however, it is designed to assess the organization, its functions, and its staffing levels and their impact on SAIFI and especially CAIDI.

We have framed our assessment of CEI's organization and staffing by evaluating them from 3 perspectives as presented in Figure 7-1 below:

Figure 7-1
Elements of the Organization and Staffing Assessment



The elements of our review can be summarized as follows:

- **Sustainable Workforce:** This portion of the assessment addresses CEI's ability to maintain its staffing levels and knowledge base at a level sufficient for the company to carry out its mission with respect to system reliability. Key reliability-related functional areas of the Company are reviewed with respect to the age demographics, experience level, and current staff mobilization and training processes of the workforce.
- **Workforce Management:** This portion of the assessment focuses on the company's ability to keep pace with its inspection and maintenance requirements, to improve outage response, and to execute the capital spending plan (specifically New Business and reliability/capacity projects). It also includes recommendations on how to better utilize contractors.

- **Reliability Culture:** This portion of the assessment focuses on the Company's effort to ensure that its sustainable and well-managed workforce is aligned (at all levels) to the Company's imperative to improve overall system reliability. Through our numerous interviews (over 40 interviews with 26 individuals were conducted over a 3 month period) we were able to gain a sense of this level of alignment and we will provide some suggestions on how to maintain and enhance it amidst the ongoing business changes such as CEI's transformation to an Asset Management orientation.

The majority of the insights and recommendations contained within this section will have little if any <u>immediate</u> impact on CEI meeting its 2009 Reliability Performance Targets. However, the issues raised and concepts discussed in this section are vital to the Company's ability to achieve the objective of 10 years of sustained performance.

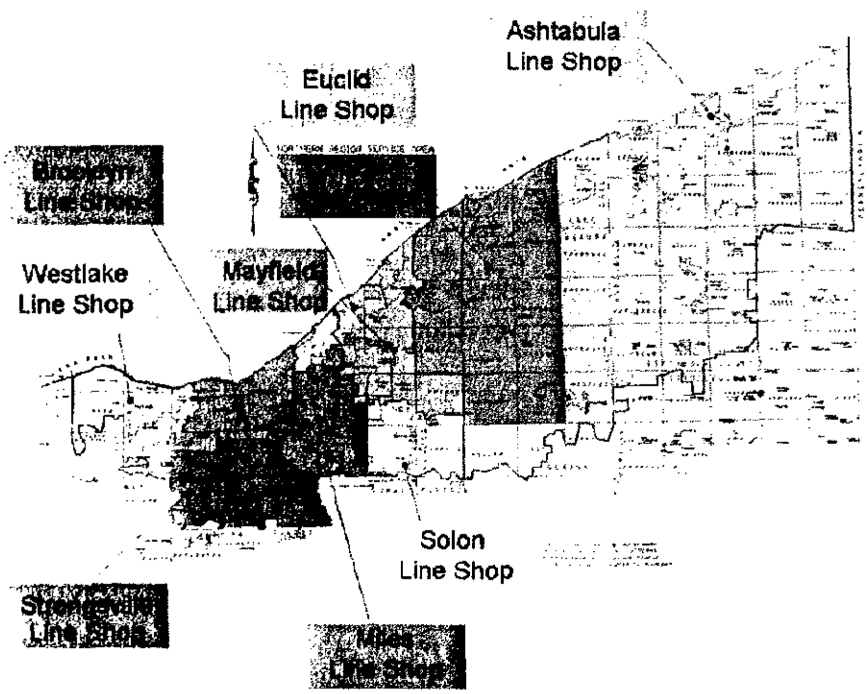
7.2 Overview of the CEI Organization Structure

The CEI electric system serves approximately 750,000 customers in a service territory that spans across Northeast Ohio and is referred to within the company as the *Northern Region* of FirstEnergy's Ohio-based electric system. The company's electric distribution network covers over 1,700 square miles of service territory and is composed of approximately 14,000 circuit miles (distribution and subtransmission); these circuits include 8,500 overhead circuit miles and 5,500 underground circuit miles.

The company headquarters are located in the south-central part of the territory in Brecksville and it manages the electric system by decomposing the service territory into 9 geographic areas referred to as *districts*. These district offices are informally referred to within the company as *line shops* or *garages*.

Figure 7-2 below provides a geographic overview of the company's service territory and its 9 major district headquarters.

Figure 7-2
CEI Service Territory



The growth conditions of the company's service territory reflect the general economic conditions of Northeast Ohio; overall, it has seen substantially no net growth in the past 5 years. Certain areas of the company are experiencing modest growth; others are in fact experiencing negative growth patterns. Figure 7-3 below summarizes the scope and compound average (customer) growth rate (CAGR) of each of the company's district operations.

Figure 7-3
Customer Count and Growth Rate by District

District	No. of Customers	2002-2006 CAGR
Ashtabula	62,136	1.2%
Brooklyn	135,553	-1.0%
Concord	67,618	0.8%
Euclid	53,302	-1.9%
Mayfield	95,667	0.4%
Miles	121,680	-1.4%
Solon	28,491	0.1%
Strongsville	104,473	0.5%
Westlake	78,106	0.6%
TOTAL	**747,026**	**-0.2%**

Each district manages its area of the network through a company and contractor workforce that is assigned from the district's line shop and is responsible for over 1000 circuit miles of electric distribution system (except Euclid) Each district has a composition of both underground (UG) and overhead (OH) circuits. Figure 7-4 below highlights the infrastructure composition of each of the districts.

Figure 7-4
Electric Infrastructure by District

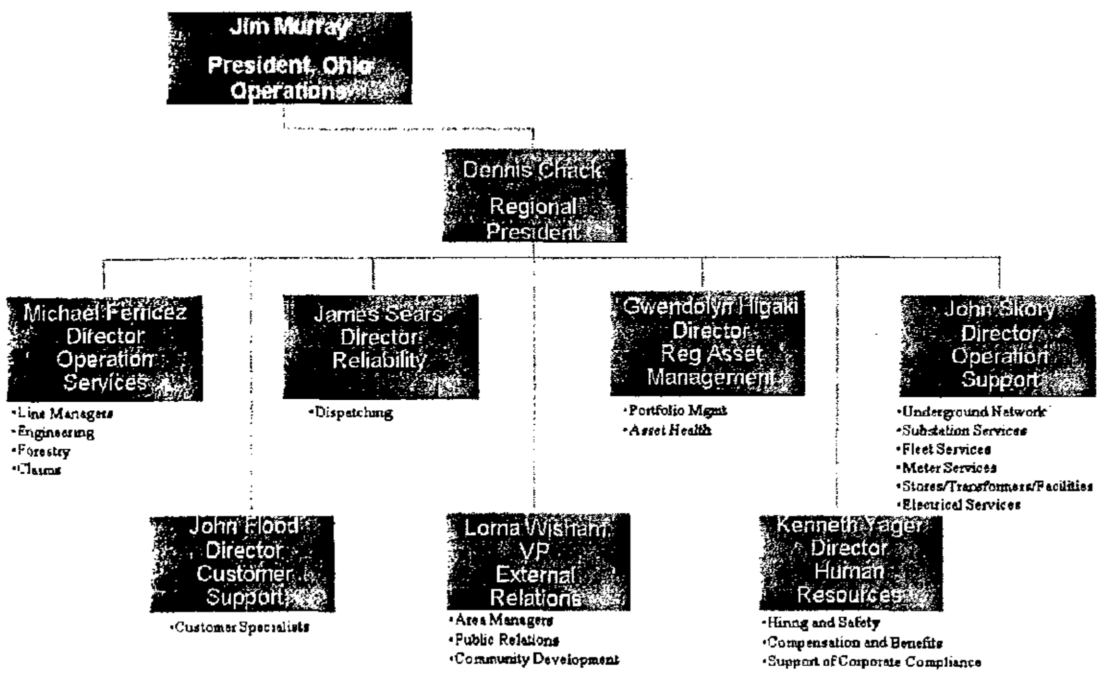
District	Customers		Circuits				
	Number	PCNT	CKT Miles	PCNT	OH Miles	UG Miles	PCNT OH
Ashtabula	62,136	8%	1,932	16%	1,638	294	85%
Brooklyn	135,553	18%	1,436	12%	981	456	68%
Concord	67,618	9%	1,953	16%	1,028	926	53%
Euclid	53,302	7%	530	4%	382	147	72%
Mayfield	95,667	13%	1,275	11%	947	329	74%
Miles	121,680	16%	1,318	11%	784	534	60%
Solon	28,491	4%	920	8%	382	530	42%
Strongsville	104,473	14%	1,407	12%	664	743	47%
Westlake	78,106	11%	1,179	10%	566	612	48%
TOTAL	**747,026**		**11,949**		**7,371**	**4,578**	**62%**

The company organizes its workforce into broad functions; these functions include:

- **Operation Services** - manages the primary *lines workforce* and is organized by the district structure noted above.
- **Operations Support** - has the primary responsibility for the substation and underground network work groups and is managed through an *East* and *West* organizational structure for substations, while one underground network group covers the entire CEI territory.
- **Other Planning and Management Functions** – includes Asset Management, Human Resources, External Relations, and Customer Support.

Figure 7-5 below presents a high-level overview of the CEI organization.

Figure 7-5
Current CEI Organization Structure



The current organization structure embodies several recent and noteworthy changes:

- The Director of Reliability role and function was recently established to provide a local leadership role and focal point for driving improvement in overall system reliability.
- The Director of Regional Asset Management was defined to be the leading operating company representative responsible for locally implementing the FirstEnergy Asset Management strategy. It is a pivotal role in the Company's ability to meet the long-term objective of 10-years' of sustained reliability performance at the agreed upon targets. It will be responsible for such elements as planning and managing the portfolio of capital projects (including staged and systematic refurbishment of aging

infrastructure), strategic staffing model, and integrated capital and O&M spend optimization.

7.3 Assessment of Organization and Staffing

The following subsections of this Section of the report summarize our assessment of the three distinct perspectives of CEI's organization and staffing as they relate to overall system reliability. Restating, the three perspectives are:

- Sustainable Workforce
- Workforce Management
- Reliability Culture

7.3.1 Sustainable Workforce

In assessing the ability of CEI to maintain a sustainable workforce, our scope spanned across the Operations Services, Operations Support, and Reliability Departments. Figure 7-6 below identifies the critical departments, functions, and positions (also known as job families) that will define the focus of this analysis.

Figure 7-6
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

Within each of these Departments/Functions/Positions there are specific challenges with respect to maintaining a sustainable workforce. From a overall perspective, the predominant issues facing the Company include a rapidly aging workforce, few succession options with respect to leadership and management positions (a topic that the company actively monitors and manages), and a resource-constrained pipeline in terms of recruiting and hiring replacement staff to address planned retirements. Figures 7-7 and 7-8 below further illustrate these points.

Figure 7-7
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%	

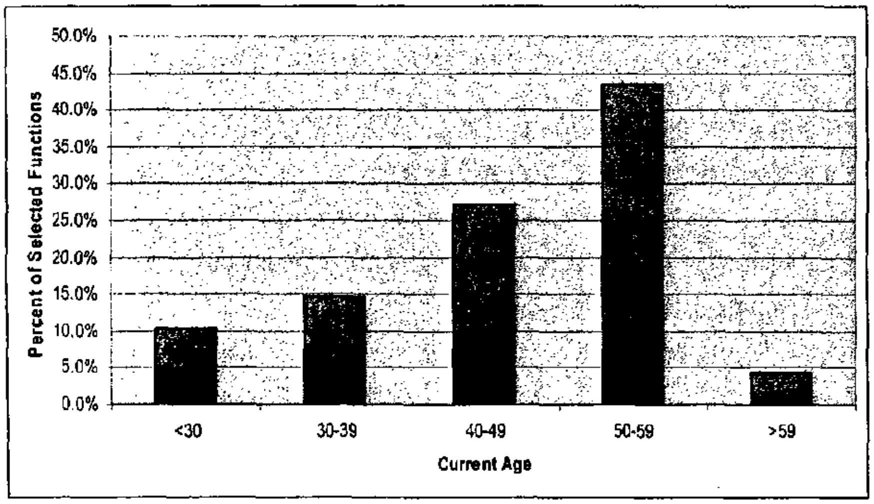


Figure 7-7 above notes that almost 48 percent of all employees within these functions are over 50 years of age (totaling 308 staff) and are likely to retire within the next 10+ years.

Figure 7-8
Leadership/Management by Age and Function

Position	Current Age					Total
	<30	30-39	40-49	50-59	>59	
Substation	0	0	8	7	1	16
Distribution Line	0	3	14	19	0	36
UG Network	0	0	3	3	0	6
Engineering Services	0	0	2	6	0	8
Regional Dispatching	0	0	0	1	1	2
TOTAL	0	3	27	36	2	68
PERCENT	0.0%	4.4%	39.7%	52.9%	2.9%	100.0%

Over 55 percent (38 of 68, as shown in Figure 7-8) of the current Leadership and Management staff in these targeted areas is also likely to retire within the next 10+ years. The pipeline for future Leaders and Managers is typically composed of the Non-Managers (included in Figure 7-7) that currently range in age from 30-39); this pipeline is clearly constrained.

Notwithstanding outside recruiting and hiring, over 40 percent of the current 30-39 year old cohort (38 of 94 members) will need to develop into leaders and managers (a particularly daunting percentage as the normal percentages of leaders/managers to staff are more in the range of 10-20 percent). This will occur at the same time when 48 percent (308 staff) of technical staff will also be retiring thereby placing additional demands on the remaining staff. This will place an enormous burden on this 30-39 year old cohort and particularly on its leaders.

This situation is not unique to CEI or to First Energy. It is typical for virtually all electric utilities in North America and Western Europe. Generally speaking, industry-wide trends to reduce O&M and capital spending during the 1990s led to hiring freezes and this has resulted in an abnormally distributed work force in terms of age demographics (very few employees were added in the 1985-2000 era). Utilities (including CEI) are now increasing their hiring efforts and simultaneously face new competition for resources from other technical fields and industries.

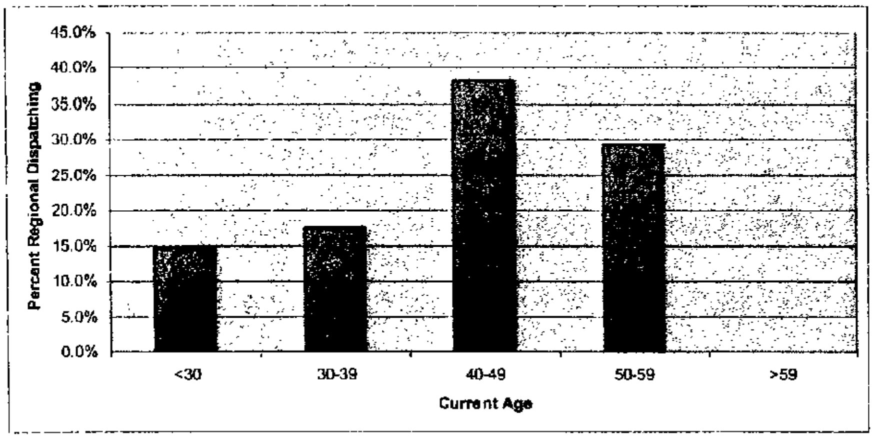
To mitigate these effects FirstEnergy has taken a number of steps to address this challenge, most notably the PSI Program. The PSI program could certainly be categorized as a "Leading Practices" approach to recruiting, training, and assimilating entry level employees. The Company's key challenge is the 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.

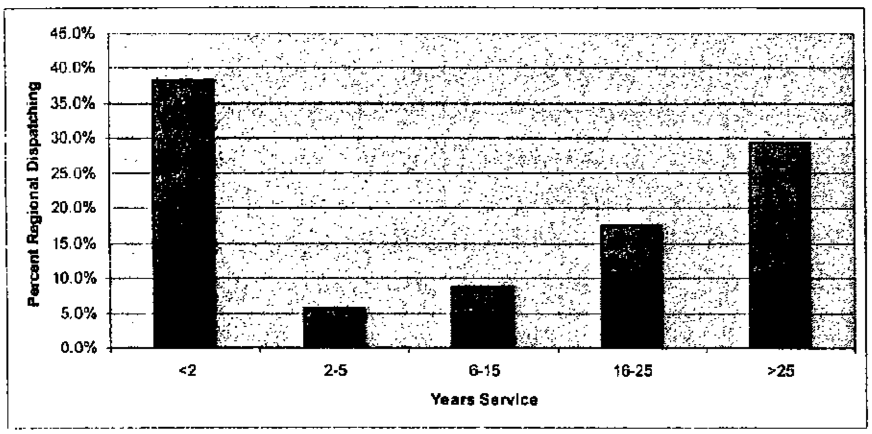
Though the issues presented as part of the high level view apply within each of the Departments/Functions listed in Figure 7-6, a look at the more critical positions offers other insights as outlined below.

Reliability

Figure 7-9 below exhibits the scale of the staffing challenge facing CEI for Regional Dispatchers. The company will need an aggressive approach to addressing the anticipated departure of almost 30 percent of the Regional Dispatchers over the next 10+ years. In so doing, CEI will likely experience some challenges in sustaining its level of performance in the timely restoration of service since more that 35 percent of the current staff has less than 2 years experience (it is easy to observe that from changing staff demographics in the next few years more than ½ of the Regional Dispatchers will have less than 5 years of experience).

Figure 7-9
Regional Dispatching Staff by Age and Experience





In conjunction with continuing to work the recruiting pipeline to replace retiring regional dispatchers, CEI should also explore ways to encourage longevity among the existing dispatching staff. During interviews it was apparent that CEI needs to consider ways to make this key position more attractive financially to high performing employees.

<u>Operations Services</u>

The profiles for the Distribution Line and Engineering Services functions are presented in Figures 7-10 and 7-11 below and they are not significantly different from the patterns previously reviewed. Over 46 percent of the Distribution Line employees will retire over the next 10+ years, as will 50 percent of the Engineering Services staff. Of particular note is the projected loss (and thus the required replacement) of 124 Distribution Linemen and 21 Distribution Specialists.

Figure 7-10
Distribution Line Staff by Age Category

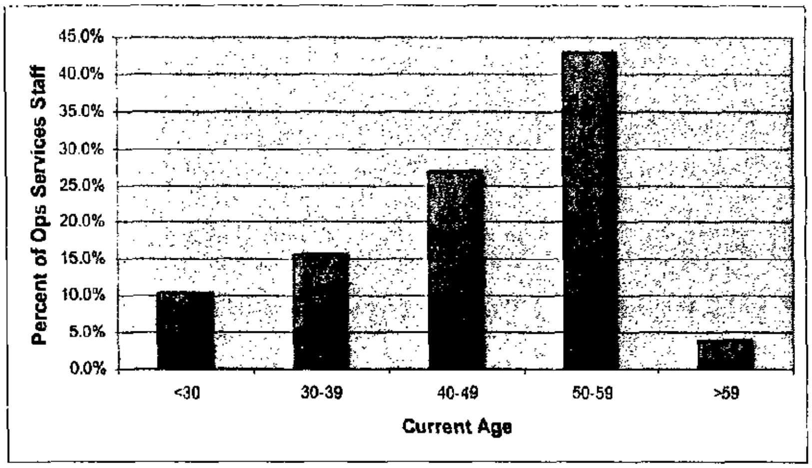
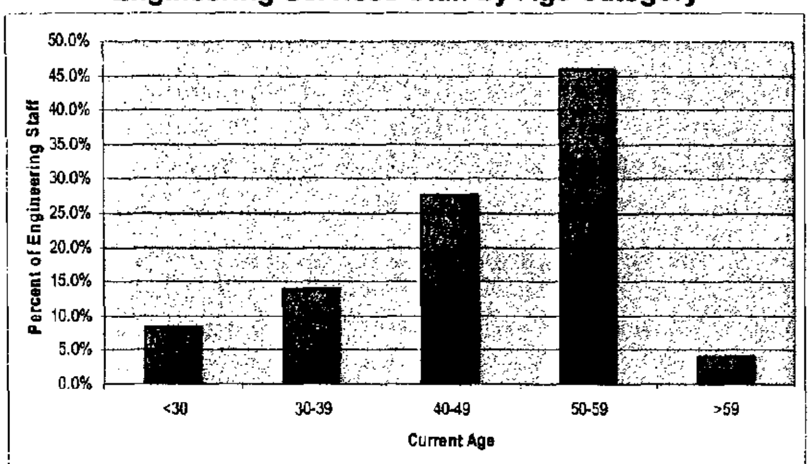


Figure 7-11
Engineering Services Staff by Age Category



As has been experienced within Regional Dispatching, the "one-for-one" replacement of experienced staff with entry level employees puts significant stress on overall outage response and we would expect degradation in CAIDI performance. This subtle effect is difficult to measure but is nevertheless real. We would encourage the Company to consider hiring and training as much as possible "in advance" of needs (as opposed to "one-for-one" replacement) to maximize the level of knowledge transfer from older, high-experience workers to their younger and skill-building replacements. We note that even the well-conceived PSI program cannot immediately replace the 30-40+ years experience represented by these 124 Distribution Linemen and 21 experienced Distribution Specialists (Designers).

Operations Support

Over 59 percent of the Substation staff is older than 50 as noted in Figure 7-12 below. Almost 79 percent of the Relay Testers as noted in Figure 7-13 below are also over 50. The extraordinarily high percentage of Relay Testers facing retirement within the next 10+ years poses a significant challenge to CEI's ability to properly maintain coordination within the substations.

Figure 7-12
Substation Staff by Age Category

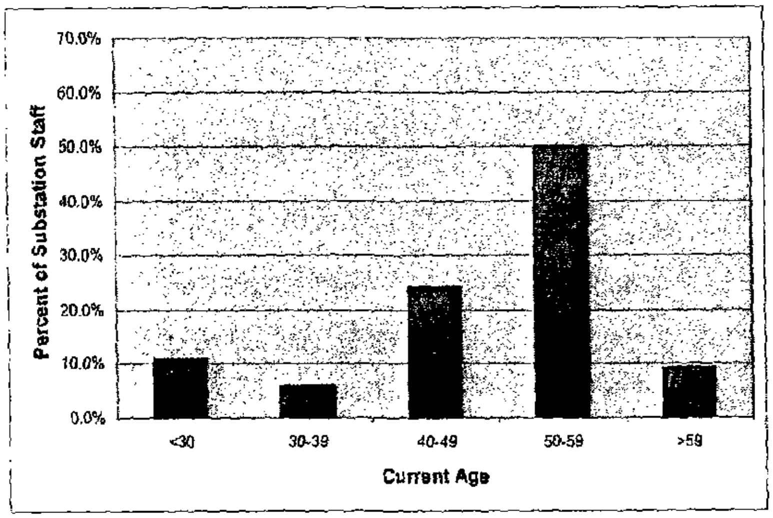
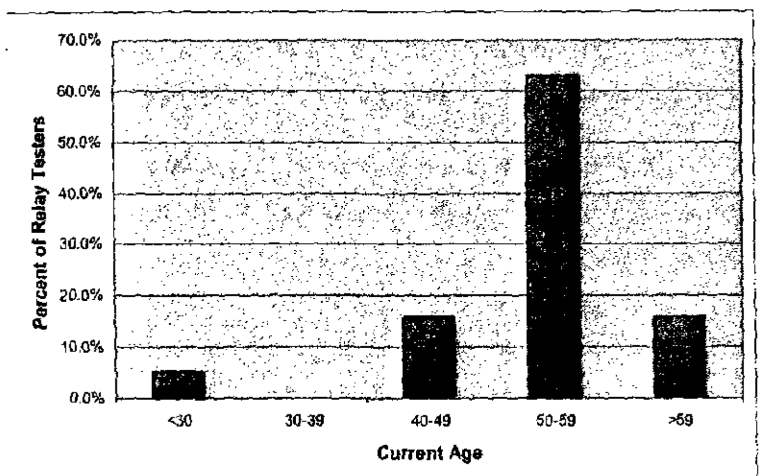
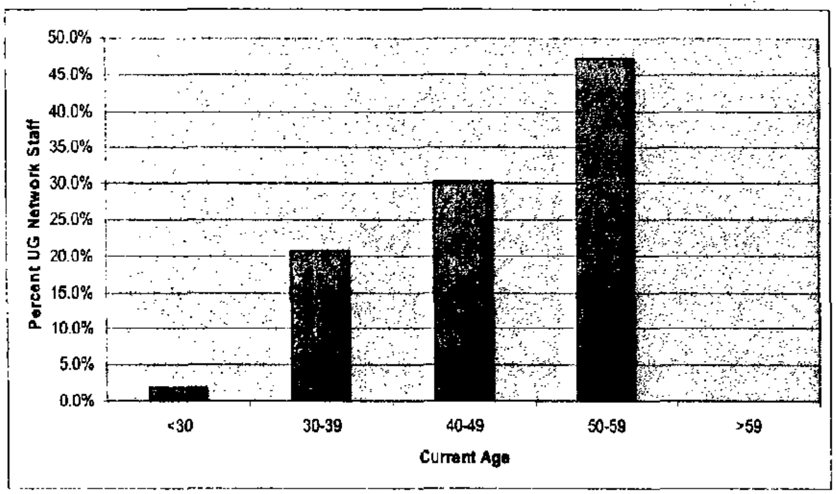


Figure 7-13
Relay Tester Staff by Age Category



Note that the Underground Network staff profile presented in Figure 7-14 below has virtually no representation among the 20- to 30-year old electricians. The convergence of the significantly aged buried cable replacement issues (noted in Section 5.0) and a retiring workforce (over 60 percent of the Underground Network staff over the next 10 years) in this work group will pose a significant challenge to CEI.

Figure 7-14
Underground Network Staff by Age Category



7.3.2 Workforce Management

This portion of the assessment addresses how the workforce and workforce management practices contribute to the company's effectiveness at maintaining and improving overall system reliability. It provides insights regarding the adequacy of CEI's staffing levels and competencies to keep pace with its inspection and maintenance program, improve outage response, and meet the requirements of the capital spending plan (specifically New Business and reliability/capacity projects).

<u>Preventive and Corrective Maintenance</u>

For purposes of analyzing CEI's capacity to perform preventive and corrective maintenance, our focus begins with the Company's existing inspection programs. The Company's preventative programs are outlined in the applicable sections of the FirstEnergy Substation Preferred Practices and Methods and the Distribution Circuit and Equipment Inspection Program Guides. Our analysis of the Company's corrective programs is related to CEI's ability to manage and address the resulting inspection exceptions (i.e. the "CM backlog").

What follows in this section is not an evaluation of the programs per se (which is separately addressed in Section 5.0); rather, it is an evaluation of the adequacy of CEI's staffing levels and competencies to meet the program requirements.

With respect to the actual inspections, CEI utilizes employees (particularly those on light duty) and contractors to meet the periodic requirements. The Company's success at satisfying these requirements varies between Operations Support (Substation) and Operations Services (Distribution) as described below:

Operations Support (Substation): Figure 7-15 below summarizes the Substation's Preventive Maintenance completion rate as measured actual vs. planned man-hours as of the end of 2006. CEI's substation completion rate was not satisfactory in 2005 and has certainly improved in 2006 (the East Region improved from 75.1 percent to 82.9 percent and the West Region improved from 54.7% to 76.4 percent). CEI currently anticipates having all substation inspection requirements completed and "current" by EOY 2007.

From a corrective maintenance perspective, the CM backlog for substation work is "current" and thus staffing appears to be adequate to resolve all inspection exceptions in a timely manner.

Figure 7-15
Substation Préventive Maintenance Performance (2005-2006)

Northern Region-East Ohio

Category	2005 Manhours			2006 Manhours			Backlog Trend	Backlog Carry
	Actual	Planned	% Compl	Actual	Planned	% Compl		
Transformers	1,618	2,062	78.5%	1,862	2,030	91.7%	(276)	168
Breakers	4,933	5,757	85.7%	2,888	3,278	88.1%	(434)	390
Relays	3,140	6,154	51.0%	3,154	5,194	60.7%	(974)	2,040
Mo. Sub Insp	4,246	4,667	91.2%	4,134	4,134	100.0%	(411)	0
All Other	387	436	88.8%	650	660	98.5%	(39)	10
Total	14,324	19,066	75.1%	12,688	15,296	82.9%	(2,134)	2,608

Norther Region-West Ohio

Category	2005 Manhours			2006 Manhours			Backlog Trend	Backlog Carry
	Actual	Planned	% Compl	Actual	Planned	% Compl		
Transformers	736	1,953	37.7%	1,044	2,354	44.4%	93	1,310
Breakers	4,397	9,618	45.7%	6,576	7,614	86.4%	(4,183)	1,038
Relays	3,581	7,561	47.4%	3,537	5,589	63.3%	(1,928)	2,052
Mo. Sub Insp	4,090	4,534	90.2%	3,215	3,245	99.1%	(414)	30
All Other	345	362	95.3%	504	669	75.3%	148	165
Total	13,149	24,028	54.7%	14,876	19,471	76.4%	(6,284)	4,595

Note: Planned Includes Backlog Carry from previous year

Operations Services (Distribution): In contrast to the Substation Preventive Maintenance (Inspection) Program noted above, CEI has been able to satisfy the line inspection requirements as specified in the relevant inspection program guide and consistent with the ESSS requirements. The Company's challenge lies in its ability to address the exceptions discovered during the inspection process. Figure 7-16 below presents the Company's CM performance for Distribution Lines.

Figure 7-16
Distribution Lines Corrective Maintenance Performance

Area	2005			2006		
	Non-Pole	Pole	Total	Non-Pole	Pole	Total
Ashtabula	0	0	0	4452	1623	6075
Brooklyn	14	29	43	2852	4919	7771
Concord	0	0	0	2248	2075	4323
Euclid	0	0	0	0	0	0
Mayfield	0	260	260	1055	140	1195
Miles	1590	5555	7145	1741	11768	13509
Solon	0	0	0	772	42	814
Strongsville	0	0	0	838	379	1217
Westlake	14	86	100	1537	1112	2649
TOTAL	1618	5930	7548	15495	22058	37553

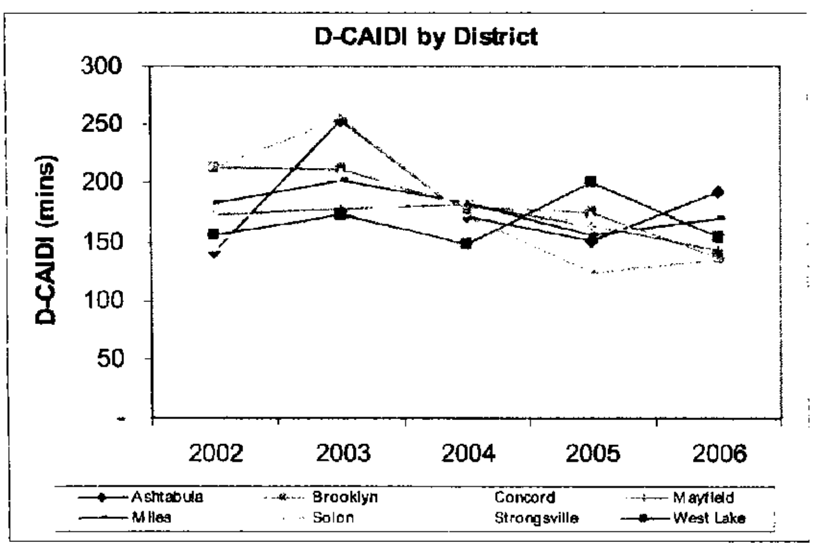
Figure 7-16 above notes a lines-related backlog of nearly 28,000 hours of pole replacement work and over 17,000 hours of non-pole related backlog that should be completed by EOY 2007. The pole related work has been contracted out to be completed as scheduled; however, it is doubtful that the CM backlog for non-pole related work (much of it accumulated during the 2005-2006 period) will be completed in 2007. Section 5.0 addresses the issues around CM backlog in the context of focus and prioritization; acknowledging that the shear number of deficiencies/exceptions is daunting, yet may or may not reflect a true view of overall reliability. Independent of any initiative to better identify the significance of/track completion of these exceptions/ deficiencies, the previously mentioned recommendation accelerate the hiring of new employees (to replace retiring employees) provides a resource pool to address this backlog (with the added benefit of on-the-job training).

Outage Response

CEI's noticeable improvement in outage response suggests that many positive factors - including effective utilization of existing staff, an optimal mix of employees and contractors, and sufficient staffing – has improved the Company's ability to restore service during system outages. Combined with the myriad of process and programmatic improvements (discussed in Section 6.0), the steady improvement in CAIDI noted over the past few years (Figure 7-17) is to be expected. Key areas, reflecting the integration of process and staffing include pre-mobilization and positioning of staff and use of the alternate shift. Both of these concepts are discussed fully in Section 6.0.

Figure 7-17
Distribution CAIDI by District

Reported District	2002	2003	2004	2005	2006
Ashtabula	140.84	254.06	171.74	150.01	191.84
Brooklyn	212.73	211.76	180.39	175.48	136.74
Concord	147.86	206.78	187.05	170.43	121.35
Euclid					
Mayfield	173.98	177.55	181.18	164.43	143.55
Miles	183.65	202.57	183.61	155.31	170.00
Solon	213.10	255.54	172.28	123.62	134.79
Strongsville	171.14	174.50	188.14	163.01	150.04
West Lake	156.30	173.65	148.17	200.38	153.70
Total	171.98	208.41	176.66	166.83	148.65



Construction

CEI has placed an appropriately high priority the Company's "summer critical" projects Most of the highest priority projects have been completed within the prescribed schedule. Proper planning and scheduling of other capital projects (most notably New Business and other Capacity or Reliability related projects) appears effective in that the capital spending plan for 2007 appears on track (with respect to projected EOY expenditures).

Clearly the lowest priority work is related to the lines-related CM activities (as noted in the prior section). The Company's key challenge is to establish the proper employee and contractor mix for addressing capital projects. For example, Figure 7-18 below notes that the 2006 New Business requirements alone accounted for 222 FTE's (and that's assuming a 12-month level effort when in fact most of the New Business work is performed in a 4-month period: July-October). Thus, there will continue to be an inherent conflict of priorities between capital projects and the more routine corrective maintenance work.

Figure 7-18
New Business 2006 Workload

Area	2006				
	NSNC	SU	NSRC	TOTAL	FTE
Ashtabula	374	893	6,344	7,611	30
Brooklyn	1,740	2,835	3,912	8,488	34
Concord	1,359	1,224	5,177	7,759	31
Euclid	0	0	0	0	0
Mayfield	2,363	3,495	5,927	11,784	47
Miles	705	1,279	3,322	5,307	21
Solon	54	834	1,365	2,252	9
Strongsville	1,684	643	3,559	5,886	24
Westlake	2,206	773	3,424	6,404	26
TOTAL	**10,485**	**11,976**	**33,030**	**55,491**	**222**

Figure 7-19 below shows the shift in CEI hours assigned to capital between 2006 and 2007 (over 40 percent increase), yet slightly less reliance on contractors (approximate 10 percent decrease) during that same time period. Capital spending is likely to increase (necessary to upgrade/replace the aging infrastructure) over the next 5 years. This increase in capital spending will be at a rate much higher than the anticipated net gain of employees. Combined with the expectation of no decrease in corrective maintenance during that same time period, CEI needs to consider a mobilizing and maintaining a larger contractor contingent on site throughout the year.

Figure 7-19
CEI Employee/Contractor Mix

Location	2006 Actuals		2007 Projected	
	Contractor Hours	CEI Hours	Contractor Hours	CEI Hours
Northern Region Asset Management	46,397	522	94,819	140
Northern Forestry	32	2,401	21,603	1,063
Northern Ohio Project Mgmnt Organization	112,963	-	12,164	-
Northern Line Operations-Shaker	-	-	-	1,788
Northern Line Operations - Concord	1,822	5,566	7,327	8,217
Northern Line Operations - Mayfield	2,860	5,458	(3,372)	8,183
Northern Line Operations - Brooklyn	47	11,895	30	17,884
Northern Line Operations - Miles	694	11,894	334	9,108
Northern Line Operations - Strongsville	255	8,822	61	6,469
Northern Line Operation - Westlake	300	3,791	773	17,832
Northern Line Operation - Euclid	-	-	-	359
Northern Region Transmission Maint	794	5,714	724	2,403
Northern Substation - East	748	13,712	5,351	28,299
Northern Substation - West	1,560	20,108	3,497	28,617
Northern Underground	896	18,239	597	22,223
Northern Service Install	366	275	124	-
Eastern Line Operations - Ashtabula	3,222	5,886	11,904	9,306
TOTAL	172,958	114,283	155,937	161,891

Figure 7-20 below provides a summarized view of our assessment of Company's workforce management performance as it relates to overall system reliability.

Figure 7-20
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

7.3.3 Reliability Culture

A key ingredient in accelerating and maintaining system reliability improvement is the extent to which there is organizational commitment and alignment in meeting the performance targets. A second, essential ingredient is the employees' willingness and flexibility to make changes, whether these changes are broad and wide-sweeping (e.g. the Asset Management Transformation initiative) or specifically targeted at key job tasks (e.g. changes in Operating Procedures).

In conducting our interviews within the CEI organization (ranging from Lineworker to Regional President and across a broad array of Departments), we were able to gain an appreciation for the CEI business culture (in terms of change readiness) and the degree of alignment among the organization around reliability-related topics. As a result, we observe that:

- CEI Management and Supervisory personnel are committed to meeting the established reliability performance targets. There are varying views regarding the "reasonableness" of these goals, but these views do no compromise the company's commitment to them.
- There appears to be an effective learning environment in terms of open discussion around reliability performance, constructive feedback, and clear accountability for reliability within the organization. We observe that these attributes are most prevalent in and around activities related to the Company's Monthly Reliability Meeting, which is well-administered, technically rigorous, and focused on performance improvement.
- The Company's recent operational improvement initiatives (e.g. "cut and run', storm mobilization, etc.) as discussed in the prior sections of this report are continually being reinforced to ensure that staff understand their impact on reliability (especially outage response).
- CEI's Asset Management initiative (outlined in Section 9.0 of this report) offers the Company its biggest opportunity and its largest risk. Most employees appear aligned behind its concept and general intent, but there are varying degrees of understanding around its charter and implementation.
- The effective integration of newly hired personnel will be a critical success factor, particularly in the Regional Dispatching Function and as the new line workers and electricians replace the more senior personnel.

Figure 7-21 below provides a qualitative "barometer" of our assessment of CEI's readiness for change, a critical success factor in implementing the 10-year vision of sustained system reliability. The key attributes necessary to support continuation of this transformation include a strong sense of teamwork among the management team, clear and defined expectations, a strong sense of accountability for results, and a certain amount of flexibility in carrying out assigned tasks.

Figure 7-21
Change Readiness Assessment

ATTRIBUTE	LOW	RELATIVE POSITION	HIGH	COMMENTS
Group Optimism	Focus on Barriers		Focus on Possibilities	Current State. Committed to meeting goals but question achievability
	Individual Success		Collaborative Success	Desired State: High Performance Team committed to meeting goals
Trust and Involvement	Distrust in Relationship		Trust in Relationship	Current State: Strong individual efforts
	Authorization Orientation		Empowered Workforce	Desired State: Fully engaged in achieving organization goals
Dignity and Respect	Unable to Negotiate		Free to Negotiate	Current State: Somewhat doubtful regarding ability to shape outcome
	Don't Feel Valued		Feel Appreciated	Desired State: Become a willing partner in joining the team
Clarity of Direction	Different Values		Shared Values	Current State: Ready to take on the challenge; a bit reticent to take on the challenge
	Fuzzy/Changing Expectations		Clear Expectations	Desired State: Energized and Motivated with a high level of belief
Market Driven Focus	Bias Towards Analysis		Bias Towards Action	Current State: A bit too mired in the past; impacted by past performance
	Internally Focused		Externally Focused	Desired State: Lead the industry in innovative approaches/solutions
Performance Accountability	Political Decision Making		Meritocracy	Current State: Strong Performance Orientation but some confusion and frustration
	Blameful		Accountable	Desired State: Focused and effective Performance Management
Learning Orientation	Close Minded		Open Minded	Current State: Flexible, but a bit measured in response
	Risk Averse		Risk Taking	Desired State: Fast and Flexible. Highly Adaptive

CEI's opportunities for improvement noted in Figure 7-21 above include the continued need to break down barriers, take initiative, and focus outside of one's current structure. This reflects one of the primary challenges facing utility management today: The manner in which organization structure is allowed to shape behaviors and focus. With all the best intentions in mind, the more strategic and comprehensive solutions tend to get trumped by sub-optimal approaches originating from organizational rather than enterprise-wide views. CEI's plan to transition to an Asset Management orientation potentially addresses this issue.

7.3 Summary of Recommendations

The following specific recommendations are submitted recognizing that their anticipated benefits will likely not impact CEI's ability to reach the 2009 targets. The issues around knowledge management, leadership and supervisory succession, and proper assimilation of new staff require a well-conceived and robust staffing strategy built in concert with a comprehensive Asset Management strategy.

OS-1	Implement an accelerated hiring program in advance of a "one-for-one" replacement to allow enhanced assimilation of and knowledge transfer to new staff in replacing more experienced, retired personnel.

Discussion

The current policy of maintaining a one-for-one hiring policy with respect to replacements is certainly valid when doing a "like for like" replacement in terms of experience, knowledge, and leadership acumen. The practical reality is the replacement of 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.

Recognizing that the probability of replacing a retiree with someone of equal knowledge is unlikely, the process should at least ensure that the apprenticeship period is completed as the more senior and experienced individuals leave the company. This will require an accelerated hiring profile, still focused on an ultimate 1 for 1 replacement, but allowing for a 2–year overlap to properly assimilate the new hire. This overlap approach will likely span a 10-year period, after which CEI can reevaluate its base staffing needs with an integrated work management program and a well-articulated contractor strategy. Figure 7-22 matches CEI's current hiring profile with our projection of attrition between 2009 and 2013 (by critical position). At the summary level, the plan calls for a net increase of 47 employees between 2009 and 2012 (and the hiring profile at least matches the projected attrition at each respective position). CEI is currently authorized to increase its head count by 50, commencing in 2009; which in essence will allow CEI to create a 2-year overlap in terms of assimilation of new staff.

NOTE: This increase need not be presented as permanent. Rather, it is intended to account for the time lag between the hiring of a new individual and the time it takes for that individual to become truly productive. Given the number of other initiatives that are ongoing within FirstEnergy/CEI (e.g. Asset Management Transformation, Increased Automation, Contractor Alliances), it would be premature to assume a higher staffing level on a permanent basis. By tying this initiative to the issues around maintaining a sustainable workforce/succession planning, CEI maintains the flexibility to remain at the increased staffing levels or return to original staffing levels, based on work level, improved processes, and employee/contractor mix strategies in the future.

Figure 7-22
Current Attrition and Hiring Projections

Function	Critical Position	5-YR Attrition	Year				
			2009	2010	2011	2012	2013
Leadership	Management	15	3	3	3	3	3
Operations Services	Engineer	10	2	2	2	2	2
	Lineworker	60	12	12	12	12	12
Operations Support	Underground Electrician	10	2	2	2	2	2
	Relay Technician	5	1	1	1	1	1
	Underground Technician	20	4	4	4	4	4
Reliability	Dispatchers	5	1	1	1	1	1
	TOTAL	125	25	25	25	25	25

Function	Critical Position	5-YR Hiring	Year				
			2009	2010	2011	2012	2013
Leadership	Management	35	7	7	7	7	7
Operations Services	Engineer	10	2	2	2	2	2
	Lineworker	99	19	20	20	20	20
Operations Support	Underground Electrician	20	4	4	4	4	4
	Relay Technician	10	2	2	2	2	2
	Underground Technician	20	4	4	4	4	4
Reliability	Dispatchers	10	2	2	2	2	2
	TOTAL	205	40	41	41	41	41

Taking a 3-year view (we recommend reassessing this profile annually based on actual attrition and the successful assimilation of new staff), the following incremental additions are presented (again, strictly for planning purposes as the actual attrition in 2008 will likely vary by position and number), indicating how to allocate the additional 50 positions currently planned for 2009:

Figure 7-23
Incremental Hiring Profile

Function	Critical Position	Incremental Hiring	2009	2010	2011
Leadership	Management	12	4	4	4
Operations Services	Engineer	0	0	0	0
	Lineworker	21	7	7	7
Operations Support	Underground Electrician	6	2	2	2
	Relay Technician	3	1	1	1
	Underground Technician	0	0	0	0
Reliability	Dispatchers	3	1	1	1
	TOTAL	45	15	15	15

OS-2	Increase focus on developing a Leadership and Management culture

Discussion

FirstEnergy has, over the years, identified high potential employees and groomed them for subsequent promotion into leadership/management positions. In fact, relative to the industry, the focus they apply to this process sets them apart from most utilities. That being said, the magnitude of the challenge confronting CEI (the shear number of Leaders and Managers retiring over the next 10-15 years coupled with the relatively low number of mid-aged/experienced individuals), may force a more aggressive recruitment strategy and earlier identification of individuals within the organization via promotion of a leadership culture. Two concerns need to be considered in adopting this recommendation:

- In terms of outside recruitment, this represents an opportunity and risk in reinforcing and/or improving CEI's culture. A potential hire needs to be reviewed relative to both technical and behavioral competencies to ensure the cultural dynamic remains consistent with the overall FirstEnergy strategy.
- With respect to internal staff development, care should be taken to ensure employee expectations are not inflated. What starts off as positively motivated, can lead to disappointment and disenfranchisement on the part of the employees if the program is not well-executed and the expectations well-articulated.

OS-3	Address CM Backlog within the current commitment time frame

Discussion

The requirement to perform patrol inspections on all distribution circuits every 5 years; and then close-out all noted exceptions within the next calendar year is more of a safety consideration than a reliability one (though there certainly is a relationship between the two). There are some alternate approaches to adopt in improving the efficiency and effectiveness of the current program (outlined in section 5.0). However, recognizing that the current ESSS requirements and commitments are driving the prioritization of resources and work planning processes, there appears to be a significant challenge in balancing these commitments with the Capital Projects.

In terms of outsourcing and contracting, FirstEnergy/CEI has done an appropriate job of segmenting out the type of O&M activities that can be contracted (e.g. Tree Trimming, Line Inspections, and Wood Pole Inspections). The majority of the items left are not scaleable enough or require too much inherent knowledge of a Company's diverse and aged system to efficiently contract to a third party.

Most capital construction work (particularly within the Distribution Line Function) can be outsourced. Therefore, we recommend that CEI align its in-house staff to address its CM Backlog within the current commitment time frame (and necessarily increase the amount of work contracted to third parties), but with the following caveats:

- Reassess the inspection requirements in terms of scope and frequency (i.e. the Feeder Backbone may warrant more frequent inspections than taps).
- Establish a variable criteria around the type of exceptions that require immediate action vs. action at the end of the next calendar year vs. those that need only be addressed as a matter of convenience (i.e. in conjunction with another activity, and not reflected as part of the CM backlog) or alternatively;
- 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).

As a side note, the accelerated hiring profile recommended in section has the side benefit of providing additional resources to address the current backlog while simultaneously providing an ideal training opportunity.

8.0 Capital Expenditure Assessment

8.1 Purpose, Scope, and Approach

The purpose of this section is to summarize our evaluation of The Illuminating Company's (CEI's or the Company's) capital spending processes and actions and to develop an assessment of their impact on the company's past and future reliability performance. Our approach to this topic has been to analyze capital expenditures in a "top-down" fashion, focusing on the logical questions or issues that informed participants would raise related to the Company's capital spending with a special focus on electric system reliability.

Specifically, we seek to answer the following key managerial and regulatory questions:

- Are CEI's past, current, and planned capital funding levels adequate to achieve the targeted reliability performance and to sustain them over the 10-year time horizon contemplated in this assessment?
- Is the company's capital spending adequately focused on reliability issues? Specifically, has the Company been able to sustain an adequate level of reliability-related investment (e.g. asset replacement, some capacity investment, and system sectionalizing and automation) or has there been a pattern of "crowding out" reliability-related capital spending by company's other business obligations (e.g. relocations, new service connections, etc.)?
- Are the company's capital planning and prioritization *processes* (broadly defined) appropriate and effective for an electric utility of its size, condition, regulatory setting, history, etc.?
- Do CEI's capital planning processes (broadly defined) have *integrity*; that is, are they implemented as designed and do they achieve the desired results?
- Will the Company's recently initiated *Asset Management* focus have a positive or negative impact on CEI's long term reliability performance?

8.2 Overall Capital Expenditure Levels

As an introduction to this section of this assessment we note that a general indicator of the overall capital expenditure levels related the Company's distribution system can be characterized by the *Gross Distribution Plant Additions* as expressed in FERC accounting terms. Figure 8-1 below presents CEI's *Gross Distribution Plant Additions* (expressed in nominal dollars) from FERC Form 1 data for the period 1990-2006:

Figure 8-1
Capital Spending Levels (1990-2006)

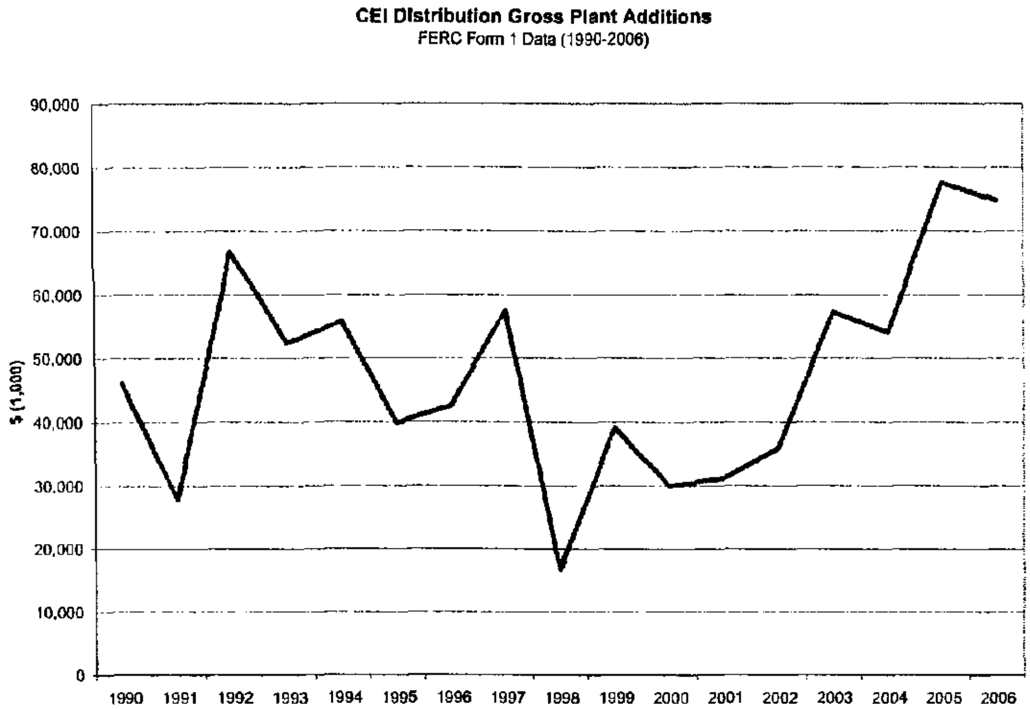


Figure 8-1 presents the Company's longitudinal spending trend. It naturally leads to a logical question - specifically, what is the "right" level of capital spending for the CEI system. Determining the "right" level of capital expenditure with precision for a large electric distribution network is undoubtedly a difficult challenge for engineers, system planners, Company management, and regulators alike. Many factors, including the age and condition of components, construction methods (overhead vs. underground), voltage, customer density, weather and environmental patterns, etc. all contribute to different spending requirements in different systems.

Correspondingly, comparative methods such as benchmarking at a detailed level are notoriously difficult to implement as a method to determine the "right" level because it is nearly impossible to normalize (i.e. "adjust") comparative spending patterns across systems to account for the key factors that drive spending.

Recognizing this overall context and the pitfalls related to such comparative analysis as noted above, our approach to this analysis has been to take a less stringent but no less relevant assessment of capital expenditures. Simply stated, we sought to assess the adequacy of CEI's relative spending in comparison to similar systems in similar environments. In our experience, the most appropriate way to make this relative comparison is using ratio of *Gross Distribution Plant Additions* over *Depreciation*. This measure 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.

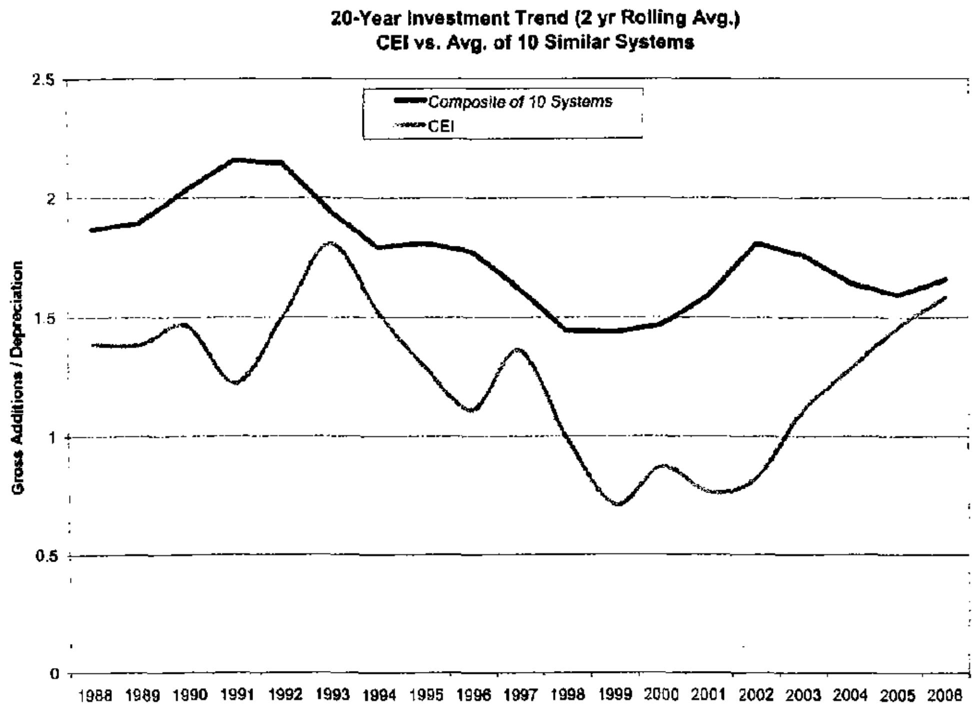
Before making our assessment, let us first explain our choice of this measure. Presuming the engineering life and accounting life of assets were synchronous, equipment costs were stable (i.e. no innovation or inflation), and the electric system is not growing (i.e. no relocations or new services), then the ratio of capital investment (as measured by gross plant account additions) over depreciation each year would theoretically be close to 1.0 (i.e. simple asset replacement). Naturally, no such hypothetical system or environment exists. In reality, many factors (inflation in material and labor costs, growth, relocations, etc.) drive this ratio up (i.e. investment would be greater than depreciation), while others drive it down (e.g. engineering life often exceeds accounting life, product innovation lowers costs, etc.).

In our experience, the combined effects of the elements noted above have resulted in the following general industry trends for this measure for U.S. based distribution systems:

- The ratio of *Gross Distribution Plant Additions* over *Depreciation* at an industry level has declined throughout the late 1980's and early 1990's from slightly greater than 2.0 to the 1.5-1.6 range in the late 1990's. We observe that these patterns occurred concurrently when:
  - Many U.S. utilities agreed to fix rates for extended periods as part of agreements related to merger approvals and "transition to competition" / deregulation initiatives. Thus, general capital spending was constrained because utilities had fewer opportunities to increase the rate base under these agreements,
  - Many commodity prices (steel, copper) and capital costs (nominal interest rates) fell and significant product innovation occurred throughout this period
  - General pricing levels stabilized from the higher inflationary patterns of the 1970's.
- Since the early 2000's the industry-wide level of capital spending (measured by gross additions relative to depreciation) has risen slightly from recent lows to stabilize in the 1.6-1.7 range.
- The general patterns noted above show up both at the industry (i.e. in aggregated form) and for most individual companies (with some variation in level that account for local conditions).

Figure 8-2 (below) 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. The composite was composed of: Columbus Southern, Dayton Power & Light, Detroit Edison, Duquesne Light, Commonwealth Edison, Kansas City Power & Light, Indianapolis Power & Light, NSTAR, PEPCo, and Pennsylvania Power & Light. To "dampen" the effect of extraordinary single year events (e.g. an extraordinary event), we have prepared this data in a 2-year rolling average approach:

Figure 8-2
CEI Capital Spending vs. Similar Systems (1988-2006)



An analysis of Figures 8-1 and 8-2 (above) leads to the following initial conclusions:

- The composite system pattern shown in the graph (Figure 8-2) does exhibit the general industry patterns described above. 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. Indeed, among the sample utilities that comprise the composite sample noted above, CEI has exhibited one of the 1 or 2 lowest levels of investment among the composite sample in *every* year since 1990.
- The level of relative investment (as measured by gross additions / depreciation) for CEI was exceptionally low in the 1988-91 and 1997-2002 eras. These eras correspond to the period just after for formation of Centerior Energy (1986) and subsequent creation of FirstEnergy (1997).
- The general patterns noted above were not unknown to either CEI management or PUCO staff. The relatively low levels of capital spending were well documented and understood by all parties throughout the periods 1987-2007.
- 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.

- The Company's current capital plans also suggest that this elevated level of capital investment will continue in 2008 and beyond. Naturally, such plans can change, but 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.

8.3 Reliability-Related Capital Investment

As noted above, the absolute and relative level of capital expenditures at CEI has been increasing and is currently at a generally "normal" level for a system of its age, condition, growth patterns, etc. From a reliability perspective, the next logical question is clear - specifically, has the capital spending (especially the recent increases) been directed (generally) at improving reliability or has the reliability-related investment been "crowded out" by other capital commitments, including new service obligations, system relocations and other mandatory municipal work, and other "non-reliability" related investment?

Our approach to this analysis has been to examine the actual spending by budget category. Figure 8-3 (below) presents CEI's 2006 distribution capital expenditures by budget category:

Figure 8-3
2006 CEI Capital Budget by Budget Category

2006 Capital Budget Variance Analysis

	Budget	Actual	Variance
Obsolete/Det Equip	$ 382,853	$ 24,590,014	$ 24,207,161
Storms	$ 253,249	$ 2,935,015	$ 2,681,766
Real Estate	$ 268,368	$ 1,075,530	$ 807,162
Failures	$ 6,197,126	$ 6,983,621	$ 786,495
Residential	$ 4,019,773	$ 4,647,702	$ 627,929
Industrial	$ (86,578)	$ 538,931	$ 625,509
Other	$ 40,000	$ 516,950	$ 476,950
Lighting	$ 1,824,905	$ 2,245,981	$ 421,076
Joint Use	$ 122,608	$ 132,526	$ 9,918
Jobbing & Contracting	$ 1,208	$ 4,554	$ 3,346
NonCap-Other		$ 2,679	$ 2,679
Regulatory Required		$ 2,005	$ 2,005
Veg Mgmt-Unplanned		$ 616	$ 616
IPP/Muni Connect		$ 273	$ 273
(blank)	$ 77,271	$ 5,963	$ (71,308)
Veg Mgmt-Planned	$ 83,280	$ 227	$ (83,053)
Commercial	$ 4,097,553	$ 3,869,357	$ (228,196)
Damage Claims	$ 742,270	$ 450,274	$ (291,996)
Facilities	$ 783,638	$ 471,691	$ (311,947)
Corrective Maint	$ 1,548,624	$ 1,173,369	$ (375,255)
Meter Related	$ 3,016,673	$ 2,576,431	$ (440,242)
Tools & Equip	$ 1,176,018	$ 733,143	$ (442,875)
New Load	$ 2,120,327	$ 973,136	$ (1,147,191)
Relocs	$ 7,060,262	$ 5,887,631	$ (1,172,631)
Sys Reinforcement	$ 4,165,502	$ 2,269,164	$ (1,896,338)
Reliability	$ 23,112,099	$ 7,051,492	$ (16,060,607)
Grand Total	$ 61,007,029	$ 69,138,273	$ 8,131,244

Analysis of Figure 8-3 (above) yields the following observations:

- First, we note that internal budgeting processes are performed on a slightly different accounting basis than external FERC reporting (as presented in Section 8.2 above). Certain overhead loadings are included in FERC accountings that are not considered in the internal budgeting exercise. Thus, the values used across these sections (i.e. Figures 8-1 and 8-2 vs. Figure 8-3) are related to the same work, but are not presented here in identical accounting terms and thus the amounts do not tie.

- In 2006, CEI's capital expenditures were $69.1million, an amount $8.1million greater than the amount originally budgeted. A similar pattern occurred in 2005, when CEI's actual capital expenditure was $47 5 million or $11.7 million greater than originally budgeted (see Figure 9-5 below). Thus, we can find no evidence that FirstEnergy is "starving" the CEI system in recent years – further confirming the conclusions noted in Section 9-2. The CEI system is clearly an investment priority within FirstEnergy system of companies.

Several of the capital budgeting classifications changed in mid-year (a not uncommon event), resulting in some confusion in evaluating the relative measure of reliability related spending. Figure 8-4 below presents a reconciliation of the 2006 budget categories to estimate the real impact on reliability related spending:

Figure 8-4
2006 CEI Capital Budget – Reliability Reconciliation

2006 Variance Reconcilliation		
Non-Reliability Elements	Variance ($M)	
Storm	$	2.7
Misc. Non Storm / Non Failure	$	2.9
Major Over Budget Items	$	5.6
Misc Under Budget	$	(2.4)
New Load/Relos/Reinf	$	(4.[illegible])
Major Under Budget Items	$	(6.6)
Reliability Elements	Variance ($M)	
Obsolete/Det Equip	$	24.2
Failures	$	0.8
Reliability	$	(16.1)
Increased "Reliability Spend"	$	8.9

Analysis of Figure 8-4 (above) in combination with Figure 8-3 (above) yields the following observations:

- Overall "reliability-related" (an imprecise term) investment was substantial, accounting for at least one-third of the 2006 capital spending. 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. There also appears to be little evidence that the there has been strong "crowding out" of reliability related investment in 2006.

Figure 8-5 below presents a similar budget assessment for the year 2005:

Figure 8-5
2005 CEI Capital Budget by Budget Category

2005 Capital Budget Variance Analysis						
		Planned		Actual		Variance
New Business	$	3,248,334	$	10,329,360	$	7,081,026
Forced	$	12,140,576	$	18,330,383	$	6,189,807
Condition	$	6,272,823	$	7,973,274	$	1,700,451
Capacity	$	179,203	$	1,076,212	$	897,009
Tools & Equip	$	94,367	$	771,166	$	676,799
Street Light	$	1,112,985	$	1,624,364	$	511,379
Facilities	$	802,327	$	941,784	$	139,457
Vegetation Mana	$	217,992	$	329,148	$	111,156
Jobbing & Contra	$	-	$	61,630	$	61,630
O&M	$	1,750,709	$	1,726,590	$	(24,119)
Meter Related	$	3,326,135	$	3,170,015	$	(156,120)
Other	$	1,247,866	$	(90,368)	$	(1,338,234)
Reliability	$	7,350,445	$	3,231,449	$	(4,118,996)
	$	37,743,762	$	49,475,007	$	11,731,245

Analysis of Figure 8-5 (above) yields the following observations:

- Budget categories changed from 2005 to 2006 (again, a not uncommon occurrence) making direct year over year comparisons difficult.
- In 2005 the spending shows that New Business and Forced (i.e. mandatory road moves, municipal work, etc.) investments were well in excess of plan, with spending on Reliability under budget by $4.1m.
- Taken together, the combination of the 2005 and 2006 reliability-related spending (i.e. the total of the two years) is still in excess of the budgeted amounts (+$8.9m (over in 2006) - $4.1m (under in 2005) or a net of +$4.8m over budget (combined 2005-2006)) and is (in total) still a strong component of the overall capital investment and at a high relative level .

8.4 Capital Planning and Improvement Processes

Our methodology to assessing CEI's *capital planning processes* (including *Project Prioritization)* is to evaluate whether they are truly holistic technical processes that 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.

Our standard for assessing these processes is not to expect a single, "best" way to approach these processes; rather, to verify that CEI is at a level of process maturity and effectiveness consistent with its size, condition, regulatory requirements, etc. and identify those area where the company may be able to improve by implementing industry best practices from other leading utilities.

Our approach to measuring the *integrity* of CEI's capital-related business processes is to assess whether these processes are implemented as planned from a multitude of dimensions. First, is the capital planning process an integral part of overall business planning and budgeting process (e.g. setting business objectives, resource strategy, etc.), rather than an adjunct activity that requires subsequent integration / coordination with other plans? Second, are the capital plans implemented as planned and actively managed? Finally, are the inevitable changes to the plan (due to external events, new information, new priorities/issues, etc.) handled in a manner that is consistent with the decisions made during the "normal" annual planning cycle?

As a large, mature, investor-owned electric utility with a substantial base of technical expertise, we would expect to find CEI conducting capital planning and improvement processes that have the following characteristics:

- **Holistic** – the processes should integrate all capital requirements (new business, reliability, etc.) into a single planning and evaluation process.
- **Need- / Issue- Driven** – the origin of capital commitments should be clearly and systematically defined business- or technical-needs that are expressly satisfied through investment in the electric system. Actual investment alternatives may satisfy multiple needs / issues (e.g. reliability and capacity) and thus further highlighting the importance of the *holistic* objective (noted above).
- **Risk Measured** – the safety, technical, economic, and socio-political risks of funding or not funding a particular investment should be an integral part of the decision-making process. Such risks should incorporate both the probability and the consequence of failing to mitigate or eliminate system needs / issues.
- **Structured** – The nature and scope of the investments (e.g. Obligation to Serve, Reliability, Mandatory vs. Discretionary) should be well classified (and validated) at the time the need or issue is identified.
- **Standardized and Documented** – The processes should be highly standardized and not dependent on key individuals, well-documented to enable ongoing training and process refinement / improvement, and create an auditable "paper-trail" to ensure proper management and post-investment assessments.
- **Peer- , Supervisor- and Executive-Reviewed** – The inputs, analyses, decisions, and results of the processes should be actively and systematically reviewed and approved by all levels of the management team to ensure that the proper technical and regulatory requirements are met.
- **Annual Scope** – They should, as a minimum, be developed as part of an annual planning effort (multiple years are preferred) and should be systematically reevaluated throughout the year. Such defined annual plans (as opposed to continuous or 'rolling' plans) enable management to assess the impact of new or deferred projects on overall planned system performance.
- **Integrated with Budgeting and Authorization** – The capital planning effort should be an integral part of the annual budgeting process and the spending authorization process; there should be little or no effort necessary to "fit" the capital plans to operational budgets.

- **Resource Independent** – Initial definitions of work should be independent from the available resources; in short, the "work should define the required resources (both company and contractor)", not the other way around.
- **Automated** – The processes should be reasonably automated with packaged or customized software tools to encourage standardized, systematic analyses across participants, general process efficiency, and sound record-keeping of results.
- **Dynamic** – The process should be capable of integrating changes to the plans throughout the year and these changes / alternatives would be evaluated through the same process.

Our specific approach has been to review CEI's capital planning and improvement process in the context of the expectations noted above through a series of interviews with key participants and to review the company documents that address these topics.

CEI's planning process as described by the Company's planning professionals is composed of the following elements:

- Planning engineers define system-based needs that drive the analysis of potential technical options or alternatives. These options are evaluated for both technical and economic performance (they may have both capital and maintenance impacts) and are expressed or summarized as a *Request for Project Approval* and known informally as an "RPA".
  - These electric system-based needs are classified using a common issue / need framework known as the *Investment Reasons*. These classifications are presented in Figure 8-6 below. A subset of these needs or issues is classified as *Mandatory* reason and will be funded if technically approved.

Figure 8-6
CEI Investment Reason Categories

Classification Category	Roll Up	Investment Reason	Definition
"C" Mandatory	Cap	CAP-New Load	Costs associated with projects required to improve relieve or correct an existing or projected voltage or thermal condition. Some specific examples include new substations, transformer additons, transformer replacement, substation capacitor installation, line capacitor installation, and feeder/exit additions.
	Cap	CAP-Sys Reinf	Costs associated with reinforcing our infrastructure. This includes line terminal upgrades, line/wave traps, line reconductors (know line rating is under rated), line upgrades (pushing more amps through line because load has increased), replacement of a breaker due to load or interrupting current limitations, rebuilds to improve capacity
	Real estate	FAC-Real Estate	Cost associated with the purchase, sale or lease of land or property, rights of way, easements, etc.
	Forced	FRC-Failures	Costs associated with replacement of failed equipment and devices.
	Forced	FRC-IPP/Muni Connect	Costs associated with interconnections requiring an Interconnection Agreement to be signed by the interconnecting party Includes charges due to scheduled or unscheduled plant shutdowns.
	Forced	FRC-Regulatory Req	Costs associated with Dx or Tx line and service projects required by federal or state regulatory bodies. These projects may not conform to our normal design and planning criteria's. Examples include replacing PCB equipment, changes to correct clearance problems, etc.
	Forced	FRC-Relocs-Highway	Costs associated with roadway or bridge projects.
	Forced	FRC-Relocs-Other	Costs associated with relocation of facilities not associated with road or bridge projects. Examples include moving overhead lines for swimming pools or sheds, etc. Moving poles for aesthetic reasons, etc. These costs can be billable or non-billable.
	Forced	FRC-Storms	Costs associated with all weather related conditions.
	Meter	MTR-Meter Related	Costs associated with the installation or removal of meters.
	New Business	NEW-NB Commercial	Costs associated with providing service to those new customers that are primarily in the business of sale or transfer of a product or service. This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution system.
	New Business	NEW-NB Industrial	Costs associated with servicing those new customers whose business primarily involves changing the form of a product This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution or transmission systems.
	New Business	NEW-NB Residential	Costs associated with servicing those new customers considered to be private households, including apartments, townhouses, condominiums and vacation homes. This includes primary and secondary extensions, and service drops required to connect these new customers to the existing distribution system.
	Other	OTH-Damage Claims	Costs and revenues resulting from First Energy claims against an outside party.
	Other	OTH-Joint Use	Costs and revenues associated with the joint occupancy of poles.
	Street Lighting	STR-Lighting	Costs associated with all forms of street lighting and lighting services. Includes community lighting, dusk to dawn and area lighting for private customers, ornamental lighting, public street and highway lighting, for municipalities and associations. This includes both scheduled and unscheduled work.
"B" Improve Reliability	Reliability	REL-Reliability	Expenses incurred to improve/reinforce the reliability of the infrastructure assets. Examples include SCADA/MOABS additions, reclosure addition to Dx lines, relaying replacements, transrupters, CRI improvements, TX reliability index, etc These costs may or may not be directed by a regulatory body.
"B" Maintain Condition	Condition	CND-Obsolete/Det Eqp	Costs associated with replacements of equipment due to inability to get parts, or outdated equipment. RTU replacements of aging equipment, full line rehab due to aging poles, transformer replacement due to gasing, breaker replacement due to poor performance or age, substation spare equipment, rebuilds because lines are falling down, carrier set replacements, batteries/charger replacements, oscillograph DFR replacements.
	Other	OTH-Other	Costs associated with miscellaneous type categories. Examples are accounting type entries (i.e. accrued vacation, uncleared construction indirects, system enhancements, etc.).
	O&M	O&M-Corrective Maint	Program or non-program O&M costs associated with the unplanned repair and maintenance of the system, which may or may not be scheduled. This excludes any capital work resulting from corrective maintenance.
	O&M	O&M-Operations	O&M costs associated with the activities related to managing and directing the operations of the company
	O&M	O&M-Preventive Maint	Program or non-program O&M costs associated with the planned repair and maintenance of the system, which may or may not be scheduled.
	Vegetation	VEG-Veg Mgmt-Planned	Costs associated with a planned tree trimming and vegetation management program.
	Vegetation	VEG-Veg Mgmt-Unpland	Costs associated with an unplanned tree trimming and vegetation management program.
"A" Value Added	Facility	FAC-Facility-Corp	Costs associated with corporate facilities projects. Includes all costs at main GO facilities related to structures and improvements, costs for furniture, equipment, roofing, landscaping, paving, electrical and HVAC.
	Facility	FAC-Facility-Region	Costs associated with regional facilities projects. Includes all costs at regional locations related to structures and improvements, costs for furniture, equipment, roofing, landscaping, paving, electrical and HVAC.
	Jobbing & Contracting	J&C-Jobbing & Contrc	For profit work associated with customer work either generated internally or requested specifically by customers. This is expense and not Capital work.
	Tools	Tool-Tools & Equip	Capital or O&M expenses associated with the purchase and upkeep of tools and work equipment. This also includes transportation tools and equipment.
	Billable	BL-NonCap-Mutual Stm	Billable costs associated with assisting other utilities as a result of weather-related conditions. Settlement rule should be 186001.

- The project's economic dimensions (cost, expected revenue, etc.) are captured and summarized in the Capital Analysis and Risk Tool (CART) system.
- The best alternative is then determined to be an "accepted" solution by the local planning staff.
- The Company's planning staff noted that before 2005 there was a rudimentary risk assessment conducted with each project. In 2006, the Company set out to enhance and further standardize its risk assessment process and made an effort to automate these standards in software tools. The company currently uses a standardized *Impact* and *Likelihood* approach to measure risk as presented in Figure 8-7 below.

Figure 8-7
Risk (Impact and Likelihood) Definition Standards

	0	1	2	3		Rating
Impact						
Loss Avoidance						
Description, financial impact	$0 to $100k	$100k to $1M	$1M to $5M	More than $5M	0	0.0
"realistic worst case" (rules of thumb)						
Regulatory Impact =	$200,000 per minute SAIDI increase					
O&M Expense =	$0.625 per customer per hour					
Revenue Impact (Tariff) =	$0.070 per customer per hour (T&D)					
Other Expense =	$0 Special Equipment, Contract Labor, Contract Penalties, etc.					
Non-Financial Impact						
Safety	No impact reducing potential exposures or improving safety performance	Minimal impact reducing potential exposures or improving safety performance	Moderate impact reducing potential exposures or improving safety performance	Current violation of OSHA and/or NESC	0	Max
Political/Regulatory	No Impact	Minor Impact (locally)	Moderate Impact (PUC Reporting)	Significant Impact (Regional Action)	0	0.0
Customer Impact	No Impact	0-2,500 Local	2,500-10,000 PUC Notification	>10,000 Major Outage	0	Avg Max
Outage Duration	< 1 Hour	> 1 Hour < 8 Hours	> 8 Hours < 24 Hours	> 24 Hours	0	0.0 0.0
				Impact Score =		0.0
Likelihood						
Application/ Asset Performance						
Performance history	No Issue	Minor Issues (Sporadic)	Minor Issues (Increasing Trend)	>1 Major Perf. Issue	0	Avg
Life expectancy	New - long term life expectancy	Component is beyond life expectancy - maintainable	Component is beyond life expectancy - non maintainable	Definitive signs of eminent failure within one year	0	0.0
Asset Utilization						
Asset Utilization	Within nameplate rating	Over nameplate rating (Flat Trend)	Over nameplate rating (Increasing Trend)	Exceeding Moderate Loss of Life	0	0.0
				Likelihood Score =		0.0

- Under the normal, annual planning cycle, the "accepted" solutions enter a formal, multi-level review process that ultimately results in an approval, deferral, or rejection of the proposed RPA. If the RPA is approved, the associated capital expenditure will become a component of the CEI capital budget. The current review process includes the following levels:
  - A *Peer Review* by the CEI planning staff to ensure that options are exhaustively and correctly technically analyzed,
  - An *Operating Company Review* that in the past (pre-2006) has been composed as an assessment by Regional Directors; it has recently (2006) been expanded to include operating company officers,
  - An FE *Corporate Portfolio* review that is also performed by a Capital Review Committee of leaders across the FirstEnergy system.
- The primary output of this multi-phased approach is a project ranking or prioritization. This process ranks the discretionary spending based on system impact and risk.
- Periodically throughout the year, unplanned or materially revised RPAs will reenter this assessment process and will be addressed on an exception basis.
- Throughout the year, approved projects are begun after authorization when construction activities must be initiated according to construction plan. These projects are commissioned in the SAP system through the definition of the *Work Breakdown Structure* (WBS).
  - Prior to 2007, these projects were assigned to the respective construction management professionals (in Lines, Substations, etc.) for management and implementation. Then and now, project and schedule results are monitored monthly through the CEI Project Status Update Meeting, and a project-level review of all active projects is performed with particular focus on the summer-critical projects addressing high risk issues.

- In 2006, the Company initiated a monthly *Capital Allocation Meeting* (CAM) to more actively monitor and manage the execution of the capital expenditure plan; and as such is a detailed review of variance reports and changes to the plan.

Our overall assessment of CEI's capital planning and prioritization *processes* can be summarized in the following way:

- 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 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.

- Since approximately the year 2000, many major U.S.-based investor-owned utilities (of a size and scope similar to CEI and FirstEnergy) have made significant improvements in their capital planning processes and tools to realize the characteristics outlined in the opening paragraphs of this section. To date, FirstEnergy and CEI could be best be described as making adequate but by no means industry-leading progress in these areas.

- Implementing industry best practices would lead to the development of integrated systems to link the investment evaluation process and subsequent prioritization and funding to overall strategy 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 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.

8.5 Capital Processes Integrity

Our assessment of the *integrity* of CEI's capital-related business processes has been focused on whether these processes have been implemented as they are designed. This assessment would ideally have multiple dimensions, specifically:

- Does CEI, in fact, execute the planning processes as they are designed?
- Are the capital plans implemented as they are planned (i.e. – did "approved" projects actually get built and on what schedule)?
- Are the inevitable changes to the plan (due to external events, new information, new priorities/issues, etc.) handled in a way that is consistent with all other investments?

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.

In independent assessments such as this study, we are frequently challenged to assess an organization's overall Asset Management capability (our frame of reference is our global experience with utilities, not solely a U.S. perspective). The technology-related information issues noted above are a critical dimension of this assessment. Figure 8-8 below highlights a perspective on the typical evolution that organizations follow as they transform to an Asset Management model:

Figure 8-8
Typical Evolution of Asset Management Capabilities

Pre-Asset Management Companies	Novice Asset Managers	Competent AM Companies	World Class AM Companies
• Organized in Geographic Division Structure • All Asset Management decisions made by local division management • Annual budget allocation "negotiated" among division leadership • Design standards sometimes centralized • *Maintenance and* operating standards usually flexible for local application	• Good general understanding of Asset *Management principles* • Organization Structure reflects AM/NS split • Committed to improving AM effectiveness and competence over time • Struggling with role clarity, SLA administration, <u>*accessibility of key* information, and systems needs</u>	• Rigorous understanding of all AM principles • Best in class AM process design implemented • Robust asset register in service with accurate and timely information • Effective AM information systems in place that fully meet <u>AM decision *support needs*</u> • Roles and relationships functioning well • Full life cycle plans in place and integrated into business plans	• <u>Seamless integration between corporate *finance and asset* strategy</u> • World class AM I/T Portfolio in place and ready to accommodate AM for others • Network and business performance significantly better than less mature *AM companies* • High credibility with Regulators • Network services and Asset Management are fully contestable

As it applies to <u>the IT-related elements</u> of the Company's capital planning and prioritization processes, CEI would generally fall in the novice / competent categories (based on a global scale of reference). The Company does have solid planning tools (RPA database, CART system, SAP) and is implementing new and better one (e.g. the

Navigant Consulting model), however data accessibility and more importantly data integration are weak. This is not an unusual condition for U.S.-based electric utilities.

CEI acknowledges at various levels in the organization the need to make better ex-post assessments of the actual impact of specific investments and use these assessments as key inputs to the project / alternative design process. This awareness is a critical first step toward defining the requirements and realizing the benefits of such information systems capabilities – which typically have a strong emphasis on data and systems integration.

This information improvement issue is one of the stated objectives of the Company's current *Asset Management* initiative, achievement of which will likely not occur until 2008 and beyond.

8.6 Asset Management Initiative

In late 2006 FirstEnergy initiated an Asset Management (AM) initiative aimed at improving the effectiveness of its capital investment programs, both in terms of how projects are selected and approved and how projects are managed in implementation. Given the 10-year perspective of this assessment, the implementation of this AM initiative at CEI will have a very important effect on the Company's ability to improve reliability especially in the context of the aging infrastructure challenges facing First Energy (and many other U.S. utilities).

The focus on this FirstEnergy-wide AM initiative has been to enhance how projects are managed and improve the quality of asset-related information and decision-making. It has included new organizational elements at both the holding company (FirstEnergy) and operating company (CEI) levels. CEI's AM function reports to the President of CEI and also has a matrix reporting relationship to the FirstEnergy Vice President – Asset Oversight. It will also include the implementation of new business processes and tools (noted above).

The CEI Director of Asset Management is the primary CEI manager responsible for implementing this initiative. There are 3 managers who report to the Director of Asset Management, responsible for the following three AM functions:

- **Project Management** - The project management responsibilities are focused on the timely, cost-effective, and safe implementation of the capital work program.
- **Portfolio Management** – This represents the continuing process of managing all of the Company's capital projects in the context of the overall schedule and budget. Project status and cost data is updated bi-weekly and this enables monthly reporting for the entire Company's capital project portfolio relative to budget and plan.
- **Asset Strategy** – This includes the implementation of 10 newly created positions known as Circuit Reliability Coordinators (CRCs) at CEI (FirstEnergy is implementing 70 such positions around the FirstEnergy system). CRCs will be responsible for circuit level asset history and analysis, data management and standardization, monitoring circuit-level reliability performance, and formulating projects and programs as they relate to their responsible circuits. The Company's vision is that these CRCs will be the "owners" of these circuits, with a strong sense of responsibility for their reliability performance, and will coordinate the investment projects related to their respective circuits through the necessary inspection, technical analysis, and financial / budgeting processes.

The company has a parallel corporate and operating company organizational structure. The operating company managers and director (noted above) are responsible for the implementation of these functions within CEI; the parallel corporate role is the Company's overall process owner and its manager is responsible for standardization of systems, processes, and tools across the First Energy system

FirstEnergy's corporate Asset Management leadership team has expressly recognized (and is actively managing) three primary challenges related to its Asset Management initiative. These include

- **Timing** – The FirstEnergy leadership team has set an aggressive time line to initiate the Asset Management initiative, especially as it relates to implementing the capital prioritization process and the hiring of CRCs. This is a major organizational change, with many new roles and interfaces between new participants and existing business processes and roles.
- **System Knowledge / Root Cause Analysis** - The Company is actively seeking ways to improve its ability to conduct "root cause analysis" of reliability issues. The AM leadership appropriately recognizes that this is a foundational element of improving asset-related investment decisions and will also be closely linked to the quality of the Company's asset data (see below).
- **Asset Data / Information** – FirstEnergy is seeking to become far more "predictive" (rather than "reactive") to asset failure patterns and far more accurate in the estimation of impact or benefit of system investments. A key element necessary to achieve these objectives is improved asset information (age, condition, failure patterns, loadings, etc.). This need is one of the driving factors behind the design of the new CRC role.

We generally concur with the Company's goals for the Asset Management initiative. Our observations related to this area were that the CEI executive management and FirstEnergy corporate AM leadership team have strong and clear views of scope, approach, and implementation of the AM initiative.

However, at the CEI staff level we noted uncertainty among departments about new or changed roles, responsibilities, and process interfaces (e.g. the role of CRCs v. existing inspections, the technical qualifications and expectations of the CRCs, etc.). Such uncertainty in the early stages of a major operating change is not unusual and is not yet a source of major concern. Moreover, as noted in Figure 8-8 above, we note that this struggle for "role clarity" is a very common characteristic of early stage AM transformations.

Our overall interpretation of the Company's Asset Management initiative in the context of this reliability assessment is straightforward – we believe it absolutely represents the <u>greatest opportunity</u> 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 <u>single greatest risk</u> to overall system reliability because of the potential uncertainties created by any major organization restructuring and new processes.

Figure 8-9 below summarizes some of the major risks and opportunities that CEI will face as it develops its Asset Management organization:

Figure 8-9
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 related to 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 in the next 12-24 months.

8.7 Summary of Recommendations

The following specific recommendations are submitted to the Company related to its capital expenditure processes, spending levels, and methods.

CE-1	Sustain Planned Spending Levels for the 2008-2012 Period

Discussion

The Company's current targeted spending levels over the next several years (as described above) will be at a level well above its historic average and above industry patterns. This capital spending level will enable the company to address the recommendations outlined in this report and should be adequate to realize the objective of sustained reliability improvement for the next 10 years. The key challenge for the Company will be to sustain the overall capital expenditure level and to ensure that Reliability-related expenditures are not materially diverted to other capital obligations.

CE-2	Monitor the Performance and Effectiveness of the Asset Management Initiative

Discussion

As noted, the Asset Management initiative offers the Company its greatest potential opportunity and its greatest risk with regard to sustained reliability improvement. We encourage the Company to continuously monitor the effectiveness of this program with a special focus on the key risks outlined in Figure 8-9 above.

9.0 2005 ESS Rule 10 Action Plan Compliance Review

9.1 *Purpose, Scope, and Approach for this Section*

The purpose of this section is summarize our evaluation of the Illuminating Company's (CEI's or the Company's) compliance with each provision of its 2005 ESSS Rule 10 Action Plan to determine whether CEI's missed its interim reliability targets due to non-implementation of the Action Plan items.

The Action Plan was presented to UMS Group as Exhibit A in the Company's original Request for Proposal (RFP) specification and this Exhibit (presented below) serves as the frame work for organizing our assessment. For each element of the Action Plan as presented in the Exhibit, we will:

1. Assess CEI's overall compliance with the Action Plan item.
2. Summarize CEI's overall performance in the item and direct the reader to additional specific references to CEI's performance as characterized in this report. All of the items noted in this action plan have been evaluated as part of our overall Reliability Assessment Framework. As such, our detailed assessment is noted in other sections of this report.
3. Summarize our interpretation of the impact of CEI's compliance (or non-compliance, as appropriate) on the Company's failure to meet the reliability targets.

9.2 Provisions of the ESS 2005 Rule 10 Action Plan

The Action Plan can be summarized as follows:

Figure 9-1
Exhibit A from FirstEnergy RFP

CEI 2005 ESSS Rule 10 Action Plan 4901:1-10-10(C)(2)

Index missed	Factors contributing to the miss	Individually list action taken or planned to be taken for each factor to improve performance	Estimated cost to be incurred for each action in plan	Completion date or scheduled completion date for each action
CAIDI and SAIDI	Outages to large number of customers	In addition to traditional substation employees, the First Responder Program utilizes non-traditional employees, such as mechanics, operation supervisors and office technical personnel to respond to substation and circuit outages. Employees are notified by e-page. The intent is to quickly get trained personnel, who work or live nearby affected substations, to assist CEI dispatching personnel in identifying the problem and restore service. For 2005, we will expand this process to include additional employees, conduct additional training and qualification testing, and re-emphasize management expectations for area responsibility and expedient response.	$125,000	7/31/05

CAIDI and SAIDI	Outages to large number of customers	CEI will implement additional work shifts and schedule changes to achieve increased afternoon coverage by line and substation crews.		5/31/05
CAIDI and SAIDI	Outages to large number of customers	CEI is implementing management review of circuit lockouts with restoration times greater than 60 minutes. These outages affect larger blocks of customers and have a significant impact on CAIDI.		3/31/05
CAIDI and SAIDI	Outages to large number of customers	In-depth management review of inoperable equipment on a weekly basis. Equipment out of service results in abnormal system configurations. If another outage occurs during these temporary abnormal configurations, longer duration outages are possible. In addition to prompt repair of all inoperable equipment, prioritization will be used to assure equipment that may affect the largest amount of customers for the next contingency is repaired first.		3/31/05
CAIDI and SAIDI	Outages to large number of customers	Metrics are being established to measure the dispatching/trouble crew response effectiveness to outages.		6/30/05
CAIDI and SAIDI	Outages to large number of customers	Management is proactively monitoring weather fronts and activating the CEI storm process. Specifically line, metering, substation, underground and office personnel are held on duty in advance of the storm. This practice was initiated during the second half of 2004		3/31/05
CAIDI and SAIDI	Outages to large number of customers	Overtime staffing for service restoration is being reviewed and different methods are being evaluated to increase staffing		6/30/05
SAIFI, CAIDI and SAIDI	Reduce outages due to lightning	An instantaneous relay trip (fuse save mode) is being evaluated for 50% of the 13kV circuits beginning the second quarter of 2005. Based upon results of this review, instantaneous tripping may be initiated and have an impact on improving SAIFI and CAIDI.	$150,000	9/30/05
CAIDI and SAIDI	Outages to large number of customers	Fault indicators have been installed at 170 locations on the 13kV system. The remaining 130 locations are scheduled to be accelerated and installed by the third quarter of 2005. Faults on 13kV circuits have a high contribution to CAIDI. Installation of the fault indicators helps locate the direction of the fault, thus aiding in sectionalizing the feeder and more rapidly restoring large blocks of customers.	$50,000	9/30/05
SAIFI, CAIDI and SAIDI	Isolating outages will reduce customer minutes	Single-phase units are replacing distribution three-phase line reclosers as the three-phase devices are pulled for maintenance. The change-out is accelerated if required for specific reliability work. Three-phase re-closers trip (open) all three phases for single-phase faults. Single-phase units trip the faulted phase only, thus impacting only one third of the customers. Five locations will be changed out in 2005.	$75,000	9/30/05

SAIFI, CAIDI and SAIDI	Large subtransmission supply outages	36kV sectionalizing and SCADA controlled switching has been installed at seven locations. Four additional locations will be installed in 2005. These devices will isolate faults and improve restoration efforts.	$240,000	12/31/05
SAIFI, CAIDI and SAIDI	Lengthy outages for a large number of customers	Automatic bus tie closing projects will be completed at five 13kV substations	$200,000	10/31/05
SAIFI and SAIDI	VSA circuit breaker failures	To date, 220 VSA reclosers have been identified as part of the shunt kit replacement program. A total of 164 reclosers have been retrofitted. The remaining 56 reclosers will be retrofitted by the fourth quarter of 2005. Failure of VSA reclosers to isolate individual circuit faults has resulted in total substation bank shutdowns affecting multiple circuits. Through our analysis and working with the manufacturer, the problem has been addressed with the retrofit program.	$150,000	12/31/05
CAIDI and SAIDI	Reduce long outages	Upgrade/conversion work will be completed on six 4kV circuits; Additional 4kV upgrade/conversion work (approximately 10 circuits)	$1,500,000 $5,000,000	12/31/05 12/31/06
SAIFI and SAIDI	Cable failures	An underground VLF (Very Low Frequency) tester was purchased in January 2005. The VLF tester enables us to detect problems with the cable, splices and terminations that may lead to a future cable fault. We plan to begin testing our underground feeder exit cables with the VLF tester in March. Approximately 15 miles of underground cable is scheduled for replacement in 2005.	$75,000	12/31/05
SAIFI and SAIDI	Large area subtransmission supply outages	Replace wood poles and cross-arms on four 36kV circuits	$550,000	12/31/05

9.3 CEI's Compliance ESS 2005 Rule 10 Action Plan

The following subsections refer to each specific item in the 2005 Rule 10 Action Plan noted in Figure 9-1 above.

9.3.1 First Responder Program

The company has implemented the First Responder program and has evidence that it has improved the outage response in substation events. Section 6.4.1 of this report presents a detailed assessment of this program. The specific CAIDI measurement of the actual impact of this program is difficult to measure, but the "extra eyes and ears" it provides offers dispatchers timely information to expedite the deployment of additional resources as needed.

9.3.2 Additional Shifts (Afternoon, etc.)

The company has altered operational staffing to add staff coverage during the afternoon and evening hours. Section 6.4.1 of this report noted the significant, measurable improvement in CAIDI performance from this alternative shift. Figure 6-9 notes the improvement in the afternoon and evening hours has made since this program has been implemented, cutting the average duration 25-40% during this time of day relative to 2004-era performance.

9.3.3 Management Review of Lockouts

Monitoring, review, and analysis of circuit breaker lockouts is an integral part of the company's continuous reliability analysis and the reporting of lockouts is part of the monthly reliability analysis and meeting. Section 7.3.3 of this report make note that the effectiveness of the monthly review process.

9.3.4 Management Review of Inoperable Equipment

The Company has implemented this program as planned. It maintains an database of inoperable equipment in Lotus Notes and it is actively monitored and managed by the leadership team and by the Operations and Dispatch functions. The Company has set policies on response priorities related to this list.

Based on the results of our review of Company's infrastructure and inspection processes (Section 2), this item is properly administered. We note that in the June Reliability Report there was some incorrect data that had a reliability impact (Grant Substation event), although we observe no evidence that this is a widespread problem.

9.3.5 Management Monitoring of Weather

The company has implemented a program to significantly improve its weather monitoring and pre-storm mobilization. Section 6.4.1 of this report highlights the detailed actions the company has taken regarding this item. Figure 6-5 and Figure 6-6 have noted that this effort has been successful at reducing the duration of outages in storm conditions. Our recommendations encourage the Company to expand and systematize this initiative.

9.3.6 Overtime and Additional Staffing

The Company has employed all of the leading industry practices with respect to staffing (e.g. alternate shift, first responder program, call-out process, extending shifts), with discernment on balancing the inherent efficiencies of extending shifts with proper attention to remaining within time parameters (length of work day, rest periods, etc.) relating to employee safety. A sampling of overtime profiles in June (selected as it represents the convergence of completing summer critical jobs, storm season, assimilation of first half inspection results, and the start of new business related activity) indicated an approximate overall 20 percent factor across the Operations Services and Operations Support organizations. This is considered reasonable, given the timing (peak activity period). Obviously, as the Company institutes the accelerated hiring program recommended in Section 7.0, these percentages will decrease.

9.3.7 Analysis of Instantaneous Trip of Relays

The Company has implemented this action item. Section 5.2.3 of this report provides an extensive discussion. At present CEI has the instantaneous trip set on all 398 13kV circuits except for 33 circuits in which the instant trip had been set but was disabled due to concern over customer complaints about excessive momentaries. We have recommended that the instant trip and timed re-close be evaluated on a case-by-case basis based on considerations such as whether the feeder is virtually all underground (e.g., the 11kV system) and whether re-closing is likely to be successful due to clearing of a temporary fault.

9.3.8 Installation of Fault Indicators

Fault indicators were installed at 170 locations on the 13kV system in the first half on 2005 with the remaining 130 locations accelerated and installed in the second half on 2005. These indicators have been installed at the feed point cable poles of the 13kV system. They are designed to help locate the direction of the fault, thus aiding in sectionalizing the feeder and more rapidly restoring large blocks of customers. This program was expanded after 2005 to include 100 additional locations on the 4kV system.

9.3.9 Isolating outages to reduce CMI (Single Phase Reclosers)

The three-phase units were intended to be changed-out as they are maintained or required for specific reliability work. CEI completed a total of 9 site replacements in 2006, including the 5 locations committed to the PUCO for 2005.

9.3.10 Large subtransmission supply outages (Sectionalizing)

The Company has been in compliance on this Action Plan and it has yielded outstanding results. Section 3.4.1 of this report notes that as a result of these actions the sub-transmission related minutes of interruption have fallen to their lower relative level since 2001. Figure 3-6 in Section 3 highlights these results and offers related commentary of these improvements.

9.3.11 Lengthy outages for a large number of customers (Bus Ties)

The Company has implemented the corresponding Bus Tie initiative in the targeted substations. The Company actively monitors the performance of these devices as part of the ongoing reliability analysis and Monthly Reliability report and briefing.

9.3.12 VSA circuit breaker failures

These VSA breakers have been retrofitted and the corresponding failure pattern has been mitigated.

9.3.13 Reduce long outages (4kv Upgrade Work)

The 2005 4kV upgrade work of six circuits was completed in 2006. Six of the ten circuits scheduled for upgrade work in 2006 have been completed in 2007. The balance of the work has been temporarily deferred, primarily as a result of contractor availability. The Company has conducted the preparatory work (vegetation management) on all of the circuits and has noted measurable reliability improvement on both the upgraded and original portions of the network for these circuits.

9.3.14 Cable failures (VLF Testing and Replacement

The Company has implemented this Action Plan and realized some successful reliability improvement. Section 5.5 of this report provides a summary of these actions and its impact. We noted that recommendation SI-7 in our report suggests the Company continue this initiative on a wider population of exit cables with high level of attention paid to the cost-effectiveness of each replacement candidate.

9.3.15 Large area subtransmission supply outages (Pole Replacement)

The Company has been in compliance on this Action Plan and it has yielded reliability improvement results. Section 3.4.1 of this report notes that as a result of these actions the transmission related minutes of interruption have returned to (normal) relative level 2002. Figure 3-6 in Section 3 highlights these results and offers related commentary of these improvements.

Figure 9-2 below is a table that summarizes the Compliance with the 2005 ESS Action Plan and its overall impact on reliability.

Figure 9-2
Summary of 2005 ESS Action Plan Compliance and Impact

Item	Compliance	Impact Summary
First Responder Program	Yes	This is an effective effort that should be emulated by other utilities.
Additional Shifts (Afternoon, etc.)	Yes	Excellent, measurable improvement in outage duration during the new shift hours. This has been a very effective program.
Management Review of Lockouts	Yes	Effective.
Management Review of Inoperable Equipment	Yes	Effective. The Company should have continued diligence in its accuracy.
Management Monitoring of Weather	Yes	Measurable improvement in CAIDI in storm conditions.
Overtime and Additional Staffing	Yes	Improving with the implementation of other staffing initiatives
Analysis of Instantaneous Trip of Relays	Yes	Improvements have been realized. We offer recommendations for continued analysis of the instantaneous trip in selected locations
Installation of Fault Indicators	Yes	These devices have been installed and the program was expanded after 2005 to include elements of the 4kv system.
Isolating outages will reduce customer minutes (single phase reclosers)	No	The 2005 commitment of 5 devices was deferred to 2006 and then exceeded as 9 devices were installed
Large subtransmission supply outages (sectionalizing)	Yes	Excellent results. Sub-transmission SAIFI at it lowest relative level in 5 years.
Lengthy outages for a large number of customers (bus ties)	Yes	Installed and actively monitored.
VSA circuit breaker failures	Yes	Improvement realized.
Reduce long outages (4kV Upgrade)	Delayed and partially deferred	All of the preparatory work a majority of the upgrade work has been completed (but delayed). Measurable reliability improvements have been realized.
Cable failures (VLF)	Yes	Improvement to date noted. We recommend continued, selective testing to identify cost-effective replacement candidates.

Large area subtransmission supply outages (Pole Replacement 36Kv)	Yes	Results realized. Transmission SAIFI has returned to a proper level from its 2003-4 era peak.

10.0 Appendix

10.1 RFP to Final Report Cross Reference

RFP Reference		Report Section Reference
Area	Topic	
1.3 b	Assessment of Distribution Infrastructure	Section 2.0
1.3 c	Assessment of Capital Improvement Process	Section 8.0
1.3 d	Assessment of Maintenance Practices	Sections 2.4.3; 5.2.2; 5.3.4; 5.4.2 and 7.3.2
1.3 e	Assessment of Organization and Staffing	Section 7.0
1.3 f	Assessment of Outage Management	Section 6.0
1.3 g	Assessment of Costs	Section 1.0
1.3 h	Other Topics	
1.3 h(1)	Compliance with 2005 ESSS Rule 10 Action Plan	Section 9.0
1.3 h(2)	Geographic Area Review	Sections 3.4.2; 6.3; and 7.3.2
1.3 h(3)	New Technologies (Distribution Automation and Adaptive Relaying)	Section 5.2.3

10.2 List of Data References

ID	DESCRIPTION	PURPOSE
UMS-001	Electronic Copy of Presentation Package	Basic CEI System Information (Org. Charts, Demographics)
UMS-002	5-YRS of OMS Data	Reliability Analysis and Selection of 15 CKT/3 Substations
UMS-003	Vegetation Management Program Description	Reliability Analysis/Requested for July 11th
UMS-004	Worst Circuit Program Description	Reliability Analysis/Requested for July 11th
UMS-005	*Animal Guarding Program*	Reliability Analysis/Requested for July 11th
UMS-006	Lightning Protection Program Description	Reliability Analysis/Requested for July 11th
UMS-007	Substation IM&T Preferred Practices	Distribution Infrastructure and Maintenance Practices Assessment (Pending Selection prior to July 6th)
UMS-008	Circuit/Line IM&T Preferred Practices	Distribution Infrastructure and Maintenance Practices Assessment
UMS-009	Equipment IM&T Preferred Practices	Distribution Infrastructure and Maintenance Practices Assessment
UMS-010	Corrective Maintenance Policies/ Procedures/Practices	Distribution Infrastructure and Maintenance Practices Assessment
UMS-011	Inventory of Assets for the 3 Substations Targeted for Inspection	Distribution Infrastructure and Maintenance Practices Assessment (Pending Selection prior to July 6th)
UMS-012	Most Recent Line Inspection Reports for the 15 Circuits Targeted for Inspection	Distribution Infrastructure and Maintenance Practices Assessment (Pending Selection prior to July 6th)
UMS-013	High Level Map (Transmission and Substation Level) indicating District Boundaries	General System and Company Information (Suggest Copy of Map we reviewed at CEI Offices)
UMS-014	CEI ED Asset Summary	General System and Company Information
UMS-015	2006 and Most Recent Quarterly Service Reliability Report	General System and Company Information
UMS-016	Results of Most Recent Customer Satisfaction Survey	General System and Company Information
UMS-017	Description of IT Platforms used to Manage Distribution Assets	General System and Company Information
UMS-018	CEI Distribution System Assessment and Future Outlook (Long Term Plan)	General System and Company Information
UMS-019	Most Recent Commissioners Meeting Presentation	General System and Company Information
UMS-020	Most Recent *Annual Compliance Report re: Reliability*	General System and Company Information
UMS-021	CEI Performance Dashboard Report and EOY 2006 Performance Metrics	General System and Company Information
UMS-022	*Description of CEI Electrical System* (Demographics and Assets by Line and Substation District Offices)	General System and Company Information
UMS-023	Substation ID by Number	Aid in correlating CKT numbering system with that provided to PUCO

ID	DESCRIPTION	PURPOSE
UMS-024	Explanation of Minutes on sub-cause code U (Subtransmission)	Refer to e-mail of 7/5/2007
UMS-025	Wood Pole Inspection Reports for 15 CKTS being inspected	Distribution Infrastructure Assessment
UMS-026	Recloser Inspection Reports for 15 CKTS being inspected	Distribution Infrastructure Assessment
UMS-027	Most Recent Substation Inspection Reports for the 3 Substations being inspected	Distribution Infrastructure Assessment
UMS-028	Remote Controlled Switch Inspection Reports for Targeted Inspections	Distribution Infrastructure Assessment
UMS-029	Corrective Maintenance EOY Backlog (by Substation District Office) (3 YRS) (No. and HRS)	Maintenance Practices Assessment
UMS-030	Corrective Maintenance EOY Backlog (by Line District) (3 YRS) (No, and HRS)	Maintenance Practices Assessment
UMS-031	PM Performance (EOY for 3 YRS) (% Based on No. and Planned HRS)	Maintenance Practices Assessment
UMS-032	CEI Maintenance Prioritization Process (Incorporate into CM EOY and PM EOY Backlog)	Maintenance Practices Assessment
UMS-033	OMS System Manual and Procedures	Reliability Analysis
UMS-034	Worst Circuit List	Reliability Analysis
UMS-035	Worst Devices List	Reliability Analysis
UMS-036	District Reliability Performance Report	Reliability Analysis
UMS-037	5-YRS Customer Count (by District)	Reliability Analysis
UMS-038	Switching Plans: To What Extent do the Exist/Where are they Maintained	Reliability Analysis
UMS-039	Call-Out Response (Average Time and PCNT Response by District	Outage Restoration Assessment
UMS-040	Staffing by District and Shift (include Age Demographics)	Organization and Staffing Assessment
UMS-041	Staffing by Substation District Office (include Age Demographics)	Organization and Staffing Assessment
UMS-042	Contractor Utilization (Staffing Profile, Type of Work, Location)	Organization and Staffing Assessment
UMS-043	CEI Overtime Profile (Line District, Substation Office, Position)	Organization and Staffing Assessment
UMS-044	Engineering Staffing Profile, Locations and Functions	Organization and Staffing Assessment
UMS-045	New Business in 2006, Projected in 2007 by Line COC/Include Response Times	Organization and Staffing Assessment

ID	DESCRIPTION	PURPOSE
UMS-046	Contracting Philosophy by Line District	Organization and Staffing Assessment
UMS-047	Vital Staffing Reports (Hiring Profile, Anticipated Attrition by Line/Substation District	Organization and Staffing Assessment
UMS-048	Key Statistics by Line District (Refer to Comments)	Organization and Staffing Assessment
UMS-049	Capital Budgeting and Prioritization Process Overview	Capital Improvement Process Assessment
UMS-050	Capital Spending (Planned and Actual for 2005 and 2006) (by Category and Individual Project)	Capital Improvement Process Assessment
UMS-051	Capital Budget for 2007 (Summarize Major Reliability Initiatives)	Capital Improvement Process Assessment
UMS-052	O&M Spending for 2005 and 2006 (Category/Highlight Major Reliability Programs)	Capital Improvement Process Assessment
UMS-053	O&M Budget for 2007 (by Category and Highlight Major Reliability Programs)	Capital Improvement Process Assessment
UMS-054	Explanation of Exclusions for OMS Reliability Information	Reliability Analysis
UMS-055	Monthly Reliability Meeting Presentation	Reliability Analysis
UMS-056	Osmose Technical Specification	Distribution Infrastructure Assessment
UMS-057	Guidelines for Inspection of Distribution Wood Poles for Decay	Distribution Infrastructure Assessment
UMS-058	Guidelines for Reinforcement of Wood Poles	Distribution Infrastructure Assessment
UMS-059	OH/UG Line Miles and Customers for all 13kV abd 4kV Circuits	Reliability Analysis
UMS-060	Asset Management Plan and/or Philosophy	Capital Improvement Process Assessment
UMS-061	Dispatcher Staffing Profile (with ages or years of experience)	Organization and Staffing Assessment
UMS-062	Network Cable Staffing Profile lwith Age Demographics)	Organization and Staffing Assessment
UMS-063	Cable System Presentation	Reliability Assessment
UMS-064	Line Inspection Status (as of 12/31/2006)	Organization and Staffing Assessment
UMS-065	Breakout of Capital Projects (Substation and Line/Internal and Contracted	Organization and Staffing Assessment
UMS-066	Storm Plan	Reliability Analysis
UMS-067	PSI Study (Per Discussion with Mark Julian)	Organization and Staffing Assessment
UMS-068	Circuit Study for Potential Sectionalizing	Reliability Analysis
UMS-069	2005/2006 Capital Budgeting Information (FERC Compatible)	Capital Improvement Process Assessment

10.3 List of Cleveland Electric Illuminating Company Staff Interviews

Cleveland Electric Illuminating Company Interview Participants	
Name	**Title / Responsibility**
Tracy Mayse	Manager, Substation Services (East)
Jim Sears	Director, Reliability
Tom Solanics	Supervisor, Engineering Services
Ron Kuczma	Manager, Substation Services (West)
Larry Oyler	Lineworker Leader (Miles)
Mike Zelenik	Line Leader Shift (Strongsville)
Pat Kelly	Lineworker Leader (Concord)
Frank Vanthoor	Line Leader Shift (Westlake)
Ray Hanzlik	Lines Manager (Mayfield and Solon)
Jim Forristal	Supervisor, Regional Operations Line (Mayfield)
Bill Robinson	Line Leader Shift (Ashtabula)
Stan Goodrich	Lineworker Leader (Mayfield)
Gwen Higaki	Director, Asset Management
Brian Larrick	Line Manager (Strongsville)
Darry Lindemann	Supervisor, Regional Operations Line (Shaker Heights)
John Skory	Director, Operations Support Services
Steve Miller	Advanced Engineer
Gerry Western	Manager, Forestry Services
Heinz Limmer	Manager, Lines (Concord)
Dan Bellmore	Manager, Dispatching
Matt Slagle	Manager, Underground Network
Tom Kopchick	Supervisor, Engineering
Dennis Chack	Regional President, Northern
Paula Sutkowski	Manager, ED Reg. Asset Strategy
Frank Dibbs	Manager, ED Reg. Projects and Portfolio
Mike Ferncez	Director, Operations Services
Doug Disterhof	Supervisor, Engineering Services
Nick Lizanich	Vice President, Asset Oversight
Tony Hurley	Director, ED Asset Management

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

PUCO DR # 4 **The information contained herein is Confidential in accordance with R.C. 4901.16. Please do not disclose.**

1. Please explain in detail what is meant by the following statement found in Section A3.e of the Plan "the need to expend capital for equipment far earlier than before"? Additionally, how does this action relate to the Company's commitment stated in Section A3.g of the Plan?

2. For the following statement found in Section A3.e of the Plan "the need to replace components of an aging distribution system", please provide rationale as to why the Company believes that this action is different from its current and past capital investment plans and operation & maintenance practices. Additionally, how does this action relate to the Company's commitment stated in Section A3.g of the Plan?

3. Please describe the relationship between Rider DSI and CEI's commitment to maintain its capital spending (including transmission) at a minimum level of $84.7 million for at least five years (based on the first long-term recommendation on Page 32 of the UMS report). Include any implications for the other two operating companies.

4. Please describe the relationship between Rider DSI and CEI's commitment to establish and adhere to "Reliability-related" and capacity investments at levels, percentage-wise commensurate with those for 2007 (based on the second long-term recommendation on Page 32 of the UMS report). Include any implications for the other two operating companies.

5. Please describe the relationship between: (1) FE's commitment to spend at least $1 billion on distribution system investments during the years 2009 through 2013; and (2) the third long-term recommendation on Page 32 of the UMS report to develop a comprehensive plan to replace and/or refurbish the current electric distribution infrastructure. Include any implications for the other two operating companies.

6. For each of FE's Ohio operating companies, please provide total capital expenditures for distribution-related facilities (69 kV and below) for each of the years 2003 through 2007.

7. For each of the operating companies, please provide capital budget variance analysis [example to use Figure 8.3 of the UMS Report titled "2007 Focused Assessment of the Cleveland Electric Illuminating Company"] for years 2002 through 2008 year-to-date, by operating company, by year. At a minimum, please utilize all of the budget categories listed on the aforementioned Figure 8.3 when providing the requested capital budget variance analysis.

8. For each of the operating companies, please provide the capital budget [example to use Figure 8.3 of the UMS Report titled "2007 Focused Assessment of the

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

Cleveland Electric Illuminating Company"] for years 2009 through 2013, by operating company, by year. At a minimum, please utilize all of the budget categories listed on Figure 8.3 of the UMS Report titled "2007 Focused Assessment of the Cleveland Electric Illuminating Company" when providing the requested capital budgets.

9. For each of the following Company capital budget categories listed below, please provide a listing of all major projects [$100,000 or greater] that are included in these budget categories within the Company's budget for each of the years 2009 through 2013, by operating company, by budget category, by year. For each major project listed, include the following: a project identification code, a description of the project [include size of facility], a description of the projects intended purpose [what does the Company plan to accomplish by completing the project], what part of the operating company's territory [location] is impacted, what quantifiable impact does the project have on SAIFI, what quantifiable impact does the project have on CAIDI, the project's budgeted dollar amount included in the budget for the year, total budgeted dollar amount for the completion of the project start-to-finish [multi-year projects], planned start date for each project, planned completion date for each project.

    a. Obsolete/Deteriorated Equipment
    b. Failures
    c. System Reinforcement
    d. Reliability
    e. New Load

10. For each of FE's Ohio operating companies, please provide a ranking of the top 10 categories in terms of capital-investment dollars spent during each of the years 2003 through 2007 including the expenditure amount associated with each category.

11. For each of FE's Ohio operating companies, please provide a ranking of the top 10 categories in terms of capital-investment dollars projected to be spent during each of the years 2009 through 2013 including the estimated expenditure amount associated with each category.

12. For each of FE's Ohio operating companies, please provide total capital expenditures for distribution-related facilities, including the proposed $1 billion capital investment plan (69 kV and below), that are budgeted, planned, or projected for each of the years 2009 through 2013.

13. Please provide a detailed description of how FE and its Ohio operating companies would decide which distribution capital projects would be implemented during the years 2009 through 2013 if Rider DSI were approved.

14. For each of the following operation and maintenance [O&M] expense categories listed below, please provide a comparison of budgeted dollars to actual dollars expensed for the years 2002 through 2008 year-to-date, by operating company, by

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

O&M expense category, by year.

a. Operations Supervision and Engineering
b. Load Dispatching - Operations
c. Station – Operations
   i. Station Inspections
   ii. Other
d. Overhead Line – Operations
   i. Overhead Line Inspections
   ii. Overhead Equipment Inspections
   iii. Distribution Pole Inspections
   iv. Other
e. Street Lighting & Signal System - Operations
f. Meter Expense – Operations
g. Customer Installations – Operations
h. Miscellaneous – Operations
i. Rents – Operations
j. Maintenance Supervision and Engineering
k. Maintenance of Structures
l. Maintenance of Station Equipment
   i. Transformer Maintenance
   ii. Circuit Breaker Maintenance
   iii. Bus and Switchgear Maintenance
   iv. Capacitor Maintenance
   v. Relay Maintenance
   vi. Underground Exit Cable Maintenance
   vii. Conductor Maintenance
   viii. Station Lightning Arrester Maintenance
   ix. Vegetation Management
   x. Station Animal Mitigation
   xi. Other
m. Maintenance of Overhead Lines
   i. Vegetation Management
   ii. Recloser Maintenance
   iii. Switchgear Maintenance
   iv. Capacitor Maintenance
   v. Conductor Maintenance
   vi. Lightning Mitigation
   vii. Animal Mitigation
   viii. Cutout Maintenance
   ix. Insulator Maintenance
   x. Pole and Crossarm Maintenance
   xi. Regulator Maintenance
   xii. Other
n. Maintenance of Underground Lines
   i. Underground Conductor Maintenance
   ii. Padmount Transformer Maintenance

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

- iii. Switchgear Maintenance
- iv. Station Exit Cable
- v. Vegetation Management
- vi. Other

- o. Maintenance of Line Transformers
- p. Maintenance of Street Lighting & Signal System
- q. Maintenance of Meters
- r. Maintenance of Miscellaneous Distribution Plant

15. For each of the following operation and maintenance [O&M] expense categories listed in Data Request 9 above [items a through r including sub-categories], please provide the dollar amounts budgeted for each category and sub-category for the years 2008 through 2013, by operating company, by O&M expense category and sub-category, by year. Staff understands that the Company does not directly budget O&M expenses in this manner but Staff believes the Company can provide this information.

16. Please provide an estimate of O&M savings (and the timing of such savings) expected to result from the $1 billion FE committed to invest in its distribution system during years 2009 through 2013.

17. Please describe the impact on each operating company's O&M expenses if Rider DSI is not approved.

18. For each of FE's Ohio operating companies, please provide estimated revenues from Rider DSI during each of the years 2009 through 2013.

19. Please describe the extent to which Rider DSI revenues would be utilized for transmission capital projects over 69 kV, and provide the estimated amount of such expenditures by operating company for each of the years 2009 through 2013.

20. Please describe (quantify) the extent to which Rider DSI revenues would be used to cover Distribution O&M expenses, describe the nature of such expenses, and explain how they are incremental to those in the test year for the pending rate case.

21. Please describe any FE controls to ensure that the Rider DSI revenues were actually spent on the projects and expense categories for which they were intended, that expenditures for such projects and expense categories are incremental, and that non-incremental (baseline) expenditure levels are maintained during the years 2009 through 2013.

22. Assuming that FE were to continue measuring reliability performance as it has in the past and that FE completed its commitment to spend $1 billion on distribution capital investments, please estimate each operating company's improvement on SAIFI and CAIDI comparing their year 2014 performance against its respective average for the 3 year period 2005 through 2007.

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

23. For each of FE's Ohio operating companies, please provide the results of any reliability-related survey questions posed to customers during the years 2004 through 2008 (YTD-July), and include a copy of the survey instruments that were used.

24. Please describe the impact on each operating company's reliability if Rider DSI is not approved.

25. Please provide a detailed rationale for revising CEI's SAIDI target to 120 minutes including an explanation of how this revision is aligned with customer expectations.

26. How will this proposed revison to the SAIDI target impact the current CEI CAIDI and SAIFI targets?

27. In Donald R. Schneider's Testimony, he makes the following statement "I believe that 120 minutes represents the optimal reliability performance for CEI, and it provides an excellent value to customers when balancing reliability performance with the costs of achieving such reliability". Please provide the quantitative analysis that supports this statement.

28. Please describe how FE would react if any of the Ohio operating Companies' SAIDI performance were to exceed the upper limit of the performance band.

29. Please describe how FE would react if any of the Ohio operating Companies' SAIDI performance were to fall below the lower limit of the performance band. Include a discussion of how FE would dispose of the additional revenue from Rider DSI.

30. Please describe CEI's progress to date in implementing the short-term recommendations made by UMS in the report of its "2007 Focused Assessment," and discuss the likelihood that all of the short-term recommendations will be implemented by year-end 2008. In addition, please provide the impact these recommendations will have on CEI's CAIDI and SAIFI performance.

31. Please provide any information on the extent to which other electric utilities utilize a rear-lot-line adjustment to their reliability performance measurement and whether such an adjustment is recognized by applicable regulatory agencies.

32. Please provide the quantitative analysis that supports CEI's "Rear Lot Reduction Factor" of .5

33. Please list and describe any recommendations in UMS Report Sections 1.5.1 or 1.5.2 which CEI plans to implement during any of the years 2009 through 2013, include the cost of such implementation, the year of planned expenditure, and the respective amounts for capital and O&M. Also discuss the extent to which similar efforts are planned for OE and TE during that same time period, and if so planned,

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

provide similar cost information.

34. Please describe any plans to adapt any aspects of the UMS report to the other two operating companies and how such plans relate to Rider DSI.

35. Please describe the relationship between Rider DSI and FE's plans to initiate an enhanced vegetation management program.

36. Please describe the relationship between Rider DSI and FE's commitment to accelerate hiring to facilitate the assimilation of new personnel in advance of anticipated attrition due to retirement (based on the fourth long-term recommendation on Page 32 of the UMS report). Include any implications for the other two operating companies.

37. For the following statement found in Section A3.e of the Plan "the need to train new employees to replace retirees", please provide rationale as to why the Company believes that the cost of training new employees to replace retirees is not included in current rates.

38. For each of the following employee categories, provide the actual number of full-time new hires that the Company experienced for each of the years 2000 through 2007 and 2008 year-to-date by operating company, by year, by category.

    a. Distribution Company Management
    b. Lineworkers
    c. Underground Electricians
    d. Underground Technicians
    e. Relay Technicians
    f. Engineers
    g. Dispatchers
    h. Circuit Reliability Coordinators

39. For each of the following employee categories, provide the projected number of full-time new hires Company plans to hire for each of the years 2008 through 2013 by operating company, by year, by category.

    a. Distribution Company Management
    b. Lineworkers
    c. Underground Electricians
    d. Underground Technicians
    e. Relay Technicians
    f. Engineers
    g. Dispatchers
    h. Circuit Reliability Coordinators

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

Response:

1. In order to maintain historical reliability performance capital is needed far earlier than before in an attempt to replace equipment before it fails and to timely order equipment to ensure that the equipment is on site when needed.

2. In the past the equipment was newer and maintainable, and now it is older and is in need of more maintenance and in many cases replacement. The $1 billion capital commitment represents the Companies' minimum commitment to addressing this very large endeavor.

3. The DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. It is not a cost-based proposal to cover a single need, but rather is a high level recognition of what is needed to maintain the health and financial sustainability of each of the Companies going forward. The $84.7 million capital spend is based on the long-term recommendation of CEI's consultant report. As part of the Companies ESP, the Companies have committed to the $84.7 million spending level for CEI for the next five years. In total, the Companies have committed to make capital investments in their distribution systems in the aggregate of at least $1 billion, which includes the $84.7 million for the CEI system. The implication to the other two operating companies will be to share in some portion of the aggregate amount of $1 billion.

4. The reliability-related and capacity investments are part of the $84.7 million CEI commitment discussed above in PUCO – DR # 4 Q3 and are included in the $1 billion capital commitment. The implication to the other two operating companies will be to share in some portion of the aggregate amount of $1 billion.

5. The long-term consultant recommendation for CEI to develop a comprehensive plan to replace and / or refurbish the current electric distribution infrastructure is a work in progress. The $1 billion capital commitment contributes to the replacement and / or refurbishment of the Companies' systems.

6. Please see attachment PUCO-DR#4-Q06-Attachment 1.xls for the Companies total capital expenditures for years 2003-2007.

7. Please see attachment PUCO-DR#4-Q07-Attachment 1.xls.

8. Please see attachment PUCO-DR#4-Q08-Attachment 1.xls for the Companies preliminary capital budget for years 2009-2013.

9. Please see attachment PUCO-DR#4-Q9-Attachment 1.xls.

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

10. Please see attachment PUCO-DR#4-Q10-Attachment 1.xls for the Companies ranking of the top 10 categories in terms of capital-investment dollars spent for the years 2004-2007.

11. Please see attachment PUCO-DR#4-Q11-Attachment 1.xls for the Companies ranking of the top 10 categories in terms of preliminary capital-investment dollars projected for the years 2009-2013.

12. Please see attachment PUCO-DR#4-Q12-Attachment 1.xls for the Companies' preliminary total capital expenditures budgeted for the years 2009-2013.

13. The decision making process would not necessarily be different under a scenario where the DSI Rider was approved versus a scenario where the DSI Rider was not approved. The expectation is that reliability and overall system health will be better if the DSI Rider is approved since additional funds would be available for reliability related expenditures as well as other purposes. As stated above in response to PUCO-DR #4-Q3, the DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. While not part of the $1 billion dollar commitment, this DSI Rider may provide, as one possibility, the financial wherewithal to invest in capital projects in excess of or different from that baseline commitment.

14. Please see attachment PUCO-DR#4-Q14-Attachment 1.xls for the Companies' preliminary total capital expenditures budgeted for the years 2009-2013.

15. Please see attachment PUCO-DR#4-Q15-Attachment 1.xls.

16. Although, not quantifiable at this time, the $1 billion capital spend is generally expected to levelize O&M expenditures.

17. As stated above in response to PUCO-DR #4-Q3, the DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. This includes, but is not limited to, the financial wherewithal to cover O&M expenses incremental to those in the test year set forth in Case No. 07-551-EL-AIR. No specific analytic study was completed to estimate the level of O&M Expenses under hypothetical examples based upon differing assumptions about the outcome of the ESP proceeding.

18. The following are the estimated revenues from Rider DSI during each of the years 2009 through 2013, assuming annual SAIDI performance between 90 and 135 minutes for each of the Companies:

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

	2009	2010	2011	2012	2013
OE	$51,216,000	$52,701,000	$53,307,000	$0	$0
CEI	$45,048,000	$45,840,000	$46,231,000	$0	$0
TE	$16,663,000	$16,910,000	$17,017,000	$0	$0

19. Rider DSI revenues will not be utilized for transmission capital projects over 69 kV.

20. As stated above in response to PUCO-DR #4-Q3, the DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. Due to the broad scope of the DSI Rider and the competing needs it will be used to address, the DSI Rider cannot be divided out among its prospective components

21. The DSI Rider revenues have not been assigned project and expense categories, but rather such revenues will ensure the overall health and financial sustainability of the distribution system.

22. The prediction of future reliability performance as measured by CAIDI or SAIFI is speculative. This was recognized in the UMS report for CEI based upon the following "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." That is why the Companies have proposed using SAIDI as the single reliability index in their Electric Security Plan.

23. Please see attachment PUCO-DR#4-Q23-Attachment 1.pdf for the Companies survey results and attachment PUCO-DR#4-Q23-Attachment 2.pdf for the Companies survey instruments.

24. As stated in Mr. Schneider's testimony, significant funding is required to maintain or improve performance in each of these key areas of focus. The Companies' Plan includes a DSI Rider during the period January 1, 2009 through December 31, 2011 which will provide the Companies the financial wherewithal to remain healthy and capable of continuing their ongoing commitments to the energy delivery and customer service business. A key component of the DSI Rider is to ensure the Companies have the financial wherewithal to make investments to improve reliability. It is difficult to quantify the impact on reliability if the DSI Rider is not approved. No specific analytic

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

study was completed to gauge the impact on the Companies' reliability under hypothetical examples based upon differing assumptions about the outcome of the ESP proceeding.

25. The 120 minutes represents the optimal reliability performance for CEI, and it provides an excellent value to customers when balancing reliability performance with the costs of achieving such reliability. The reliability performance target represents second quartile performance based on IEEE performance measures.

26. The proposed revision in the Companies' ESP filing will not affect the CAIDI and SAIFI targets.

27. An analysis was performed based on 2006 SAIDI results from approximately 100 companies by IEEE. Based on this analysis, the Companies are in the second quartile performance ranging from 100-140 minutes. Therefore, the second quartile midpoint of 120 minutes was selected as the SAIDI target.

28. If any of the FirstEnergy Ohio operating Companies' SAIDI performance were to exceed the upper limit of the SAIDI performance band the Companies would perform an analysis and take steps to begin proactive steps to attempt to address the issue.

29. Improving and maintaining reliability is a continuous process that even in the best of years requires continued investments to mitigate against future problems or outages.

30. CEI is on target to implement all short term recommendations made in the UMS report by December 31, 2008. Everything else being equal, the expected reliability benefit for each UMS recommendation is set forth below:

SAIFI Improvement Recommendations:
Enhanced Tree Trimming - expected SAIFI reduction of 0.03; Lightning Protection - expected SAIFI reduction of 0.01; Line/circuit inspection and repair prioritization scheme - expected SAIFI reduction of 0.035; Sectionalize the Backbone - expected SAIFI reduction of 0.09; Replace three-phase reclosers with single-phase reclosers - negligible SAIFI impact as indicated in UMS report; Selectively apply instant trip/timed re-close - negligible SAIFI impact as indicated in UMS report; Inspect, maintain, test and repair/replace as necessary 4 kV exit cable - expected SAIFI reduction of 0.01; Use Worst Performing Devices information to develop a worst CEMI program - this recommendation primarily addresses customer satisfaction and has limited SAIFI impact; Replace failure-prone URD cable - this recommendation primarily addresses customer satisfaction and has limited SAIFI impact; Integrate the Circuit Heath Coordinators with the ESSS Inspection Program -

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

an estimated SAIFI avoidance of 0.04; Continue to address the operability of switches on the subtransmission system - these actions will prevent deterioration of subtransmission SAIFI; Continue to replace circuit breakers and relays at the substations- Expected SAIFI reduction of 0.014.

CAIDI Improvement Recommendations:
Systematize Staff Pre-Mobilization - expected CAIDI reduction of 6 minutes; Fully implement partial restoration for OHL ("Cut and Run") and URD ("Split and Hit") - expected CAIDI benefit of 4 minutes; Fully implement use of the alternate shift - expected CAIDI benefit of 4 minutes; Recruit/Train New Dispatchers - the impact of CAIDI is indeterminate in that intent of this action is to proactively avoid a negative impact to CAIDI; Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007) - Expected CAIDI reduction of 2 minutes once new service center is in service; Re-evaluate level of staffing with respect to outage response: - the impact of CAIDI is indeterminate in that intent of this action is to proactively avoid a negative impact to CAIDI; Impact of CI reduction on CMI's - an anticipated CAIDI reduction of approximately 5 minutes.

31. The Companies have not solicited information from other companies or regulatory agencies at this time. Utilities have an opportunity to apply for diverse exclusions thus it could be difficult to perform an apples-to-apples analysis.

32. The Rear Lot Reduction Factor was calculated based on the fundamental fact that CEI experiences significant issues associated with crews being able to restore service timely to customers served on rear lot circuits based on the number of such customers and the need to manually haul poles and other equipment to such sites as opposed to using trucks. As a result of the number of obstructions at such sites including trees, fences, garages, etc., restoration times are significantly longer. In an effort to establish a representative outage duration time which takes into account the challenges of rear lot construction, customer outage minutes would be multiplied by a factor of .5 ("Rear Lot Reduction Factor") on such circuits where fifty percent or more of the premises are served by rear lot facilities. A quantitative analysis supporting the .5 factors is attached.

    An analysis was performed on 2003 - 2007 data in CEI, excluding major storms, to determine the difference in restoration between circuits with rear lot and front lot construction. Of the 1086 distribution circuits in CEI, a review of the circuits identified 339 circuits with the majority of the residential customers being served from rear lot construction.

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

year	Rear Lot	Front Lot	Percent Increase over Front
2003	195.48	147.62	32.42%
2004	192.00	111.78	71.77%
2005	172.94	95.85	80.43%
2006	150.12	113.61	32.14%
2007	128.07	95.17	34.57%
		average	50.26%

33. A number of UMS recommendations were completed in 2008. CEI projects to implement the following in years 2009-2013:

UMS Report Section 1.5.1 – SAIFI Improvement Recommendations
UMS SI-3 - Line/circuit inspection and repair prioritization scheme: This process was established in 2008 and will continue.

UMS SI-4 - Sectionalize the Backbone (Tier 1 and Tier 2): Tier 2 (review of 100 circuits) will be completed in 2009 (additional expected SAIFI reduction of 0.033).

Planned Expenditures	2009	2010	2011	2012	2013
Capital	$1,533,000	$580,000	$500,000	$500,000	$500,000
O&M					

UMS SI-10 - Integrate the Circuit Heath Coordinators with the ESSS Inspection Program: This recommendation is on-going. No additional incremental costs are planned.

UMS SI-11 - Continue to address the operability of switches on the subtransmission system: Funding for this recommendation will continue.

Planned Expenditures	2009	2010	2011	2012	2013
Capital	$291,000	$500,000	$500,000	$500,000	$250,000
O&M					

UMS SI-12 - Continue to replace circuit breakers and relays at the substations: Funding for this recommendation will continue.

Planned Expenditures	2009	2010	2011	2012	2013

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

Capital	$2,500,000	$2,500,000	$2,500,000	$2,500,000	$2,500,000
O&M					

UMS Report Section 1.5.2 - CAIDI Improvement Recommendations
UMS SR-5 - Establish new service center in Claridon Township (ISD 2009) and capture benefit of new service center in Euclid (started in 2007):

Planned Expenditures	2009	2010	2011	2012	2013
Capital					
O&M	$810,000				

The results of the UMS audit have been shared with the other Operating Companies and such Companies may utilize such recommendations where applicable.

34. The results of the UMS audit have been shared with the other Operating Companies and such Companies may utilize such recommendations where applicable. The $ 1 billion capital commitment will contribute to such efforts.

35. As stated above in response to PUCO-DR #4-Q3, the DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. This includes, but is not limited to, the financial wherewithal to continue the Companies enhanced vegetation management program

36. As stated above in response to PUCO-DR #4-Q3, the DSI Rider was designed to improve the overall health and financial sustainability of the distribution business and to recognize and ensure the continued reliability of the distribution system. This includes, but is not limited to an ability to accelerate hiring to facilitate the assimilation of new personnel in advance of anticipated attrition due to retirement.

37. New workers are hired at the same time existing workers continue to be employed to assure knowledge transfer. These costs are not reflected in the current rate structure.

38. Please see attachment PUCO-DR#4-Q38-Attachment 1.xls for the Companies full-time new hires for the years 2000- (year-to-date) 2008.

39. Please see attachment PUCO-DR#4-Q39-Attachment 1.xls for the Companies full-time projected new hires for the years 2008-2013.

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

OCC Set 2 – INT-27 Referring to page 5 of Company Witness Schneider's testimony in the ESP Proceeding where the Company proposes a Delivery Service Improvement Rider ("DSI Rider"):

a. Why has the Company based the proposed adjustments to the DSI Rider solely on the SAIDI index?

b. How were other reliability indices, including but not limited to CAIDI or SAIFI, considered by the Company for the purpose of making adjustments and how would these other indices be used for measuring, reporting, and determining reliability if the Company's ESP Application was approved?

c. What were the values for SAIDI, CAIDI, and SAIFI for each of the FirstEnergy EDUs for each of the years from 2000 through 2007?

d. What were the target values for SAIDI, CAIDI, and SAIFI for each of the FirstEnergy EDUs for each of the years from 2000 through 2007?

Response: Please note that the response below is confidential.

a. The Companies recognize that improvements in SAIFI can adversely affect CAIDI and improvements in CAIDI can adversely affect SAIFI. Thus, the Companies believe that SAIDI is a much better reliability performance indicator. This was also recognized in the UMS report for CEI which stated: "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." That is why the Companies have proposed using SAIDI as the single reliability index in both the DSI Rider and ESP.

b. The Companies evaluated the use of SAIFI and CAIDI and in part for the rationale set forth above determined that it would not be appropriate to include other reliability indices for the purpose of making adjustments to the DSI Rider. The Companies' ESP Application is separate and distinct from any reporting requirements of other reliability indices which are currently under review by Commission Staff.

c. The table below contains the Companies SAIDI, CAIDI, and SAIFI performance values for the years 2000-2007.

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

	SAIDI			CAIDI			SAIFI		
Year	**TE**	**CEI**	**OE**	**TE**	**CEI**	**OE**	**TE**	**CEI**	**OE**
2000	165.2	118.1	114.8	102.8	118.8	95.3	1.61	1.01	1.20
2001	138.6	105.2	90.7	120.0	108.0	77.7	1.16	0.97	1.17
2002	87.7	145.8	109.4	84.4	153.8	73.4	1.04	0.95	1.49
2003	89.0	152.8	109.9	89.9	124.0	85.4	0.99	1.26	1.29
2004	91.1	153.2	116.1	99.4	126.8	82.6	0.92	1.21	1.41
2005	98.6	194.3	157.4	88.8	113.7	101.3	1.11	1.71	1.55
2006	78.3	150.6	127.8	86.3	125.0	89.0	0.91	1.20	1.44
2007	86.7	125.2	100.5	94.0	106.5	88.7	0.92	1.18	1.13

d. The table below contains the Companies SAIDI, CAIDI, and SAIFI target values for the years 2000-2007.

	SAIDI			CAIDI			SAIFI		
Year	**TE**	**CEI**	**OE**	**TE**	**CEI**	**OE**	**TE**	**CEI**	**OE**
2000 **2001** **2002** **2003** **2004** **2005** **2006** **2007**	120	95	120	100	95	95	1.20	1.00	1.25

OCC Set 2
Witness: Schneider

Case No. 08-935-EL-SSO
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.

RESPONSES TO REQUEST

OCC Set 2 – INT-28 Referring to page 5 of Company Witness Schneider's testimony in the ESP Proceeding where the Company proposes to modify CEI's SAIDI target from 95 minutes to 120 minutes:

a. What is the Company's explanation and justification for also proposing a 50% Rear Lot Reduction Factor for CEI?

b. Why doesn't the increase of 25 minutes proposed for CEI's SAIDI account for all or a portion of this Rear Lot Reduction Factor?

c. If the Company applied the proposed Rear Lot Reduction Factor to CEI's SAIDI values in prior years, what would the adjusted SAIDI values be for the years 2000–2007?

Response:

a. The Companies' explanation and justification for proposing a 50% Rear Lot Reduction Factor for CEI is explained in the Companies confidential response to PUCO DR#4 Q32.

b. An increase of 25 minutes represents the optimal reliability performance for CEI, and it provides an excellent value to customers when balancing reliability performance with the costs of achieving such reliability. The reliability performance target of 120 minutes represents second quartile performance based on IEEE performance measures. The rear lot reduction factor is needed to adjust for the high percentage of rear lot facilities for reasons provided above in "a".

c. The information requested for years 2000-2002 is not readily available. The information requested for years 2003-2007 is as follows:

Year	PUCO reported minutes	SAIDI minutes w/rear lot factor applied
2003	156.2	139.2
2004	153.2	130.1
2005	194.3	160.8
2006	150.6	121.5
2007	125.2	99.6

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing the *Confidential Version of the Direct Testimony of David W. Cleaver on Behalf of the Office of the Ohio Consumers' Counsel* has been served via First Class US Mail , this 29th day of September, 2008.

Richard C. Reese
Richard C. Reese
Assistant Consumers' Counsel

PERSONS SERVED

James W. Burk
Arthur E. Korkosz
Mark A. Hayden
Ebony L. Miller
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Mark A. Whitt
Jones Day
P.O. Box 165017
Columbus, OH 43216-5017