STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

INITIAL TESTIMONY OF PETER LANZALOTTA

Filed on Behalf of

THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. Peter J. Lanzalotta, Lanzalotta & Associates LLC, 9762 Polished Stone, Columbia, Maryland 21046.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelors of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric system planning and operation, cost of service study, and utility rate design. I am a registered professional engineer in the states of Maryland and Connecticut. My prior professional experience is described in Attachment PJL-1, which is attached hereto.

I have been involved with the planning and operation of electric utility systems and with utility regulatory matters, including cost of service, cost allocation, and rate design, as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities, regulatory agencies, developers, and electricity users over a period exceeding thirty years.

In the past ten years, I have led or assisted on a number of projects focused on electric utility reliability and service quality. I have worked for many years on behalf of the City of Chicago on electric reliability-related matters, and I am currently engaged by various government offices and agencies in the states of Delaware, Maryland, Pennsylvania, and New Jersey on an ongoing basis, to help develop procedures for reporting on and evaluating electric distribution system reliability performance and remedial actions, as well as to investigate specific electric service reliability concerns.

Q. ARE YOU QUALIFIED TO OFFER EXPERT TESTIMONY IN ANY JUDICIAL OR QUASI-JUDICIAL PROCEEDINGS?

A. Yes, I have presented expert testimony before the FERC and before regulatory commissions and other judicial and legislative bodies in 17 states, the District of Columbia, and the Provinces of Alberta and Ontario. My clients have included utilities, regulatory agencies, ratepayer advocates, independent producers, industrial consumers, the United States Government, and various city and state government agencies. The proceedings in which I have testified are listed in Attachment PJL-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony, on behalf of the New Jersey Division of the Ratepayer Advocate ("Ratepayer Advocate"), addresses Atlantic City Electric Company's" ("ACE" or the "Company") reliability-related performance with respect to reliability-related Company policies, technical standards, and maintenance practices.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. My findings are as follows:

- The current reliability standards established in New Jersey provide no requirement that historical reliability performance be maintained. Rather, the current standards permit substantial degradation in reliability.
- A review of the Company's reliability performance over 2002 and the five preceding years reflect a gradual decline in reliability prior to 2002 and a significant decline in reported reliability in 2002. Without stricter reliability standards, we can expect reliability performance to continue to decline further.
- While implementation of an outage management system ("OMS") in 2002 may have contributed to the significant decline in reported reliability in 2002, there is no basis for saying that a continuing decline in system reliability performance did not contribute to this decline in reported performance.
- My review of trends in outage causes and outage impacts singles out animal contacts, equipment failures, and tree-related faults, including unknown and weather-related fault causes, as being significant contributors to the Company's historical reliability performance and to recent changes in that level of performance.

- My review of distribution transformer failures and the reliability effects of such failures indicates that these failures, and their reliability impacts, are increasing, and should be addressed by the implementation of a transformer load management ("TLM") program.
- My review of the Company's maintenance practices indicates that the maintenance interval for substation transformers was lengthened from five years to six years in 1999, and that such changes in maintenance intervals need to be questioned in light of the trends in reliability impacts of equipment failures.
- My review of the Company's policies on wildlife protection for distribution system equipment and of the trends in reliability impacts of such outages indicate the need for a more aggressive approach towards the installation of such protection.
- My review of tree-trimming data indicates that a four-year tree-trimming cycle has not yet been achieved for a number of the Company's distribution feeders, despite the Board's having ordered immediate implementation of such a cycle as of the end of 1997. Given the level of the reliability impacts of tree-related outage causes, the Company needs to increase the apparent frequency and the effectiveness of its vegetation management programs.
- The above findings collectively and individually support the need for mandatory reliability indices as proposed by Ratepayer Advocate witness John Stutz.

1. Overall Reliability Performance of ACE

Q. HAVE YOU REVIEWED THE OVERALL RELIABILITY PERFORMANCE OF THE COMPANY?

A. Yes. I have reviewed reliability data from a number of sources, including statistics provided in the Company's Annual System Performance Reports and data responses which show the following trends in commonly-used reliability indices which measure the average, system-wide frequency of service interruptions, ("SAIFI,") and the average duration of service interruptions experienced by customers, ("CAIDI.")

The following table reflects annual reliability data, including all major events. Major events are defined as when at least 10 percent of the customers in an operating area have their electric service affected, when electric service is interrupted in order to maintain system stability or security, or when service interruptions are sufficient to give rise to a State-declared state of emergency.

Year	SAIFI (all events)	CAIDI (all events)
1997	0.555	66.60
1998	0.581	91.29
1999	1.072	90.65
2000	0.682	91.55
2001	0.687	78.78
2002	1.066	105.94

SAIFI is calculated by dividing the total number of sustained customer service interruptions by the total number of customers served. For a calendar year period, SAIFI represents the average number of sustained electric service outages per customer served during that period. SAIFI may be calculated for time periods other than a calendar year as well.

CAIDI is calculated by dividing the sum of the individual customers' minutes of sustained electric service interruption by the total number of individual customer interruptions. For a calendar year period, CAIDI represents the average number of minutes of electric service interruption for each customer service interruption, or, put another way, the average outage duration. CAIDI may be calculated for time periods other than a calendar year as well, and is sometimes calculated in hours, rather than in minutes.

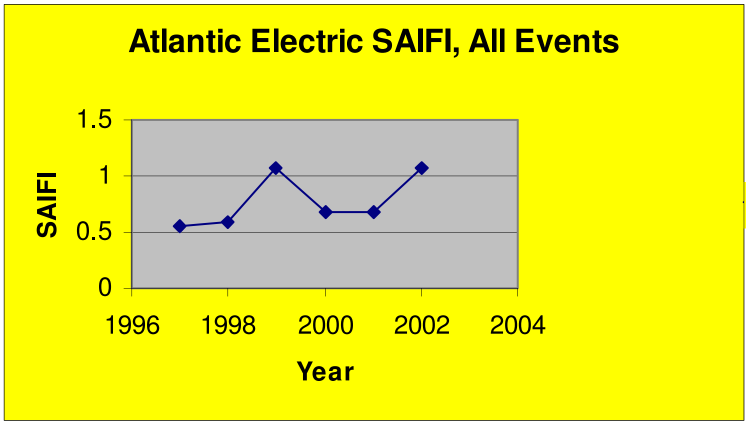
We see from the above table that, over the time period 1997 to 2002, SAIFI varied from about one-half of an interruption per year per customer to about one outage per year per customer, including all major events. Reliability performance data for 2002 shows big increases in both outage frequency (more than 50% increase) and outage duration (more than 33% increase) over the prior year, 2001. The Company claims that its implementation of its outage management system, or OMS, is inflating its SAIFI and CAIDI numbers in 2002. These claims will be discussed later in this testimony.

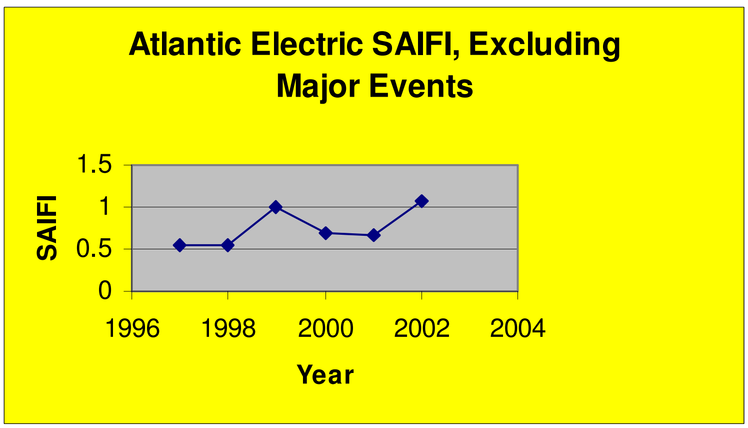
If we remove the effects of the service interruptions that occurred during major events, the Company's reliability performance during the period from 1997 through 2002 does not change significantly, as reflected in the following table.

Year	SAIFI (excludes major events)	CAIDI (excludes major events)
1997	0.555	66.60
1998	0.557	91.20
1999	1.001	92.73
2000	0.682	91.55
2001	0.674	77.16
2002	1.066	105.94

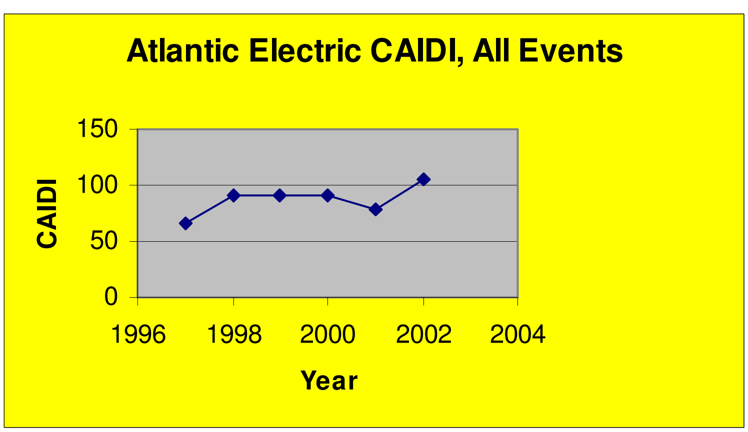
When outages during major events are ignored, the reliability performance data for 2002 still shows the same (or larger) big increases in outage frequency and outage duration that we observed in the previous table, which included major events.

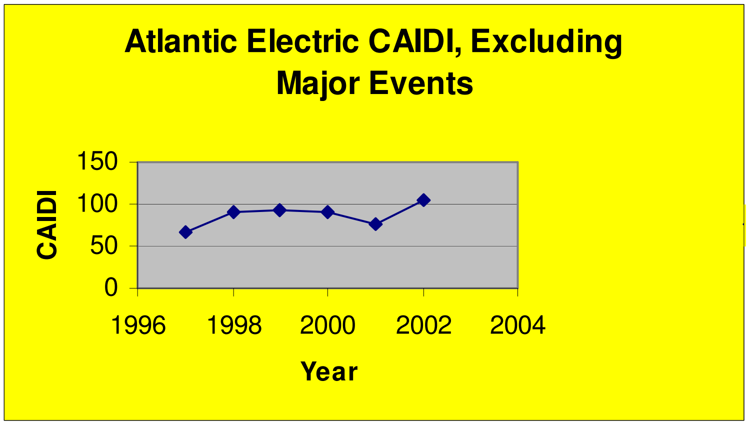
If we ignore, for the moment, the 2002 data, which the Company believes has been inflated by the operation of its OMS, the remaining 5 years of data still reflect a gradual upwards trend in both outage frequency and outage duration. This is reflected in the charts below, which show a trend of gradually increasing SAIFI in the five years leading up to 2002, regardless of whether we include or exclude major events. Of course, in 2002, SAIFI shows a large increase, to above 1.0 interruptions per customer per year, both including and excluding major events. However, we note that this level of service interruption frequency was experienced before the OMS in 1999, as well.





Similarly, the charts below show an increasing trend for CAIDI in the five years leading up to 2002, regardless of whether we include or exclude major events.





Both the frequency of interruptions, SAIFI, and average duration of interruptions, CAIDI, show large increases in 2002. Part of this increase may be due to operation of the Company's OMS, but part of this increase may also reflect a continuation of the reliability decline that has been taking place gradually over the previous five years. The Company would have us believe that all of these increases in outage frequency and duration are due to implementation of the OMS, but provides no data to rule out an actual decline in reliability performance as one factor contributing to these increases.

The current policy addressing electric utility reliability in New Jersey provides no requirement that historical reliability performance be maintained, let alone be improved. New Jersey regulations set a standard that permits substantial degradation in historical reliability performance over time. The fact that we are seeing such degradation over time should not be a surprise. The current standards permit even further degradation in reliability, and my review of reliability-related factors, which is discussed later in this testimony, indicates that we can expect this degradation to continue over time.

2. Outage Management System

Q. WHAT IS AN OUTAGE MANAGEMENT SYSTEM?

A. Outage Management Systems (OMS) are generically described as an integrated system. including a geographic information system, a software driven outage assessment tool, an energy management system, and supervisory control/data acquisition capability, in addition to other capabilities. The Company claims to be using, as of about 2002, its new OMS as the source of the electric service reliability data reflected in the tables and charts above. Previous to this, the Company used what it calls a paper system to develop this reliability data. The Company feels that the apparent increase in outage frequency in 2002, to more than 1.0 outages per customer, up from 0.69 outages per customer in 2001, and the apparent increase in outage duration in 2002, to 106 minutes per customer interruption, up from 79 minutes in 2001, are the result of its new, more accurate OMS and do not reflect actual increases in outage frequency and duration.

However, there is no basis for saying that none of these increases are due to decreased reliability. The Company's implementation of its using its OMS to produce reliability performance data was done in such a way so as to lose the comparability of reliability data from before the implementation and data from after the implementation. The Company feels that its reliability has improved in 2002, but the data provided says that reliability worsened in 2002. The Company says (see RAR-RE-31 (c)) that the JD Powers customer satisfaction study results increased from 1999 to 2003 and do not reflect customer dissatisfaction with service reliability. But, these studies do not conclusively address outage frequency or duration experience, only customers' perception of them. Considering that 1999 was a year of especially poor outage frequency reliability performance, as reflected in the tables and charts above, it is not surprising the customers' perceptions have improved since then. But, that does not address changes in reliability performance from 2001 to 2002. In addition, if the Company's service reliability has been getting worse so gradually that customers have not yet become aware of such worsening reliability, this does not mean that a continuation of such reliability trends will continue to go unnoticed.

Furthermore, we note that customers' complaints to the BPU (see RAR-SQ-11 Attach 1) have greatly increased in 2002 (1,529 complaints received) and 2003 (1,250 complaints received through 10/20/03) to date, over the numbers of complaints in 2000 (781 complaints received) and 2001 (458 complaints received). These complaint levels clearly indicate that it is possible, and even likely, that outage frequency and duration increased in 2002, precisely as indicated by the Company's filed reliability data. In sum, the Company's reliability data for 2002 and the five preceding years indicate a continuing decline in electric service reliability.

We further note that the Company's response to RAR-RE-31 says that its paper system was used for outage statistics through November of 2002, with OMS only being used for service restoration through that period. This appears to contradict the Company's representations that increases in outage frequency and duration in 2002 are due to implementation of its OMS. If the response to RAR-RE-31 is accurate, that would mean that most of the decrease in reliability performance in 2002 may not be due to implementation of the OMS, but rather to actual decreases in reliability.

The current reliability data provided by the Company only tells us that reliability performance has not improved, and that it may have worsened, recently. Also, the potential of OMS impacts on reliability performance data tell us that prior to the OMS, the Company's system of collecting outage data required by the state was not very accurate, and that, if the Company is correct about OMS being even partially responsible for perceived increases in outage frequency and duration, then reliability performance in the years prior to 2002 was much actually worse than was indicated by the reliability data presented by the Company in its Annual System Performance Reports for those years.

<u>3. Outage Trend Analysis</u>

Q. DID YOU REVIEW THE CAUSES OF OUTAGES ON THE COMPANY'S SYSTEM AND HOW THE OUTAGES ATTRIBUTED TO THESE CAUSES CHANGE OVER TIME?

A. Yes. The following three tables look at a selection of some of the leading causes of electric service interruptions on the Company's system over the period since 1997, as presented in the Company's Annual System Performance Report ("ASPR") dated May 31, 2003. The tables include all outages, including those that occurred during major events, and list the number of outage events, the number of customers interrupted, and the number of customer-minutes of interruption attributable to each of the following causes: animal, equipment failure, trees, unknown, and weather. The tables include a category labeled as “TUW” which sums up the cause categories trees, unknown, and weather, all of which I generally believe to be related, to varying degrees, to trees as a contributing factor in these outages.

ACE Outage Cause Summary - Selected Causes - All Events						
Outage Events						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	1,513	433	598	245	215	1,058
1998	1,675	357	773	271	393	1,437
1999	1,695	419	953	765	500	2,218
2000	1,165	345	404	498	451	1,353
2001	1,472	335	525	620	542	1,687
2002	1,928	1,837	1,251	1,172	901	3,324
Customers Interrupted						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	51,722	71,214	46,444	12,935	25,733	85,112
1998	67,846	58,432	41,999	22,653	37,591	102,243
1999	81,703	84,040	63,607	41,314	63,195	168,116
2000	53,634	84,555	27,238	19,007	52,346	98,591
2001	78,343	57,068	40,806	34,087	49,210	124,103
2002	59,113	92,708	101,800	100,270	64,961	267,031
Interruption Minutes						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	2,727,093	4,786,980	3,123,927	740,019	2,782,713	6,646,659
1998	5,008,802	5,863,837	3,739,363	2,169,036	3,543,949	9,452,348
1999	4,861,755	9,206,253	7,272,308	3,152,158	5,520,028	15,944,494
2000	3,595,292	6,356,493	3,768,558	1,230,718	7,243,900	12,243,176
2001	4,489,135	4,613,873	2,787,813	2,458,852	5,752,022	10,998,687
2002	4,232,778	10,965,449	9,597,906	11,619,512	9,373,396	30,590,814

Regarding the number of outage events, the number of customers interrupted, and the number of interruption minutes, several points are noteworthy. First, note that the number of equipment failures increased from 335 events in 2001 to 1,837 events in 2002, an increase of more than 400%. Even with the OMS effects on outage frequency claimed by the Company starting in 2002, the size of this increase suggests that some decrease in reliability performance is underlying these numbers.

Second, animal-related outages are a leading driver of outage events, although these outages appear to affect fewer customers and have shorter outages than some of the other causes listed. In 2002, there were still more outage events caused by animals than were caused by any other single cause category, and the number of animal-caused outage events in 2002 were higher than in any of the five preceding years.

Third, the interruption minutes caused by tree-related factors, i.e., trees, unknowns, and weather, listed as "TUW" in the chart show almost a tripling of the customer minutes of service interruptions due to these categories in 2002, with 30,590,814 minutes of interruption, compared with 10,998,687 minutes in 2001.

These trends are also reflected in the following tables, which show the percentage of outage events, the percentage of customers interrupted, and the percentage of interruption minutes attributable to the outage categories discussed above. These tables also include all outages, including those that occurred during major events.

ACE Outage Cause Summary - Selected Causes - All Events						
Percent of all Outage Events						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	43.40%	12.40%	17.20%	7.00%	6.20%	30.40%
1998	43.30%	9.20%	20.00%	7.00%	10.20%	37.20%
1999	34.30%	8.50%	19.30%	15.50%	10.10%	44.90%
2000	36.70%	10.90%	12.70%	15.70%	14.20%	42.60%
2001	37.20%	8.50%	13.30%	15.70%	13.70%	42.70%
2002	22.40%	21.30%	14.50%	13.60%	10.50%	38.60%
Percent of All Customers Interrupted						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	19.60%	27.00%	17.60%	4.90%	9.80%	32.30%
1998	24.30%	20.90%	15.00%	8.10%	13.50%	36.60%
1999	15.70%	16.10%	12.20%	7.90%	12.10%	32.20%
2000	16.10%	25.40%	8.20%	5.70%	15.70%	29.60%
2001	23.20%	16.90%	12.10%	10.10%	14.60%	36.80%
2002	11.20%	17.50%	19.20%	18.90%	12.30%	50.40%
Percent of All Interruption Minutes						
	Animal	Equip Fail	Tree	Unknown	Weather	TUW
1997	15.50%	27.30%	17.80%	4.20%	15.90%	37.90%
1998	19.60%	23.00%	14.70%	8.50%	13.90%	37.10%
1999	10.30%	19.50%	15.40%	6.70%	11.70%	33.80%
2000	11.80%	20.90%	12.40%	4.00%	23.80%	40.20%
2001	16.90%	17.30%	10.50%	9.20%	21.60%	41.30%
2002	7.50%	19.50%	17.10%	20.70%	16.70%	54.50%

Note that animal-caused outage events, as a percentage of all outage events, have decreased over time, even while the number of such events has increased. This is happening because other outage cause categories are increasing faster, especially equipment failure, which increased from between about 8% to 12% of all outage events in the period 1997-2001 to more than 21% of all outage events in 2002. While

OMS implementation may have increased the reported outage frequency and outage duration statistics, there is no indication that OMS implementation selectively increases the impact of some fault categories significantly more than the impacts of other fault categories. There is, therefore, reason to believe that an increase in equipment failure outages may be at least partially responsible for this apparent increase in the number of reported outage events caused by equipment failures.

Note, also, that tree faults and associated faults, listed under "TUW", have not increased as a percentage of outage events over time. However, the percentage of customers interrupted due to TUW faults increased to more than 50% in 2002 after varying from 30% to 37% during the previous five years. Similarly, the percentage of interruption minutes caused by tree-related and associated causes increased in 2002 to more than 54% of all interruption minutes, after varying between 37% and 41% for the previous five years. These percentage increases in 2002 indicate that the reliability effects of trees and associated fault causes have increased in 2002, relative to other fault causes, and that the reliability effects of these fault causes are much higher than was previously evident from the reliability data.

I will address aspects of equipment failures, animal-caused outages, and tree-related outages in the following sections of my testimony.

<u>4. Equipment Failure</u>

Distribution Transformer Monitoring

Q. PLEASE DESCRIBE WHAT DISTRIBUTION TRANSFORMER MONITORING IS AND WHAT ITS VALUE IS TO SYSTEM RELIABILITY.

A. Distribution transformers are those transformers on pole tops and on concrete pads in people's yards. They are very numerous and there is no contingency backup for them when they fail. When a distribution transformer fails, the customers connected to that transformer usually lose service until the transformer is fixed or replaced. There can be as few as one customer and as many as twenty residential customers served by each distribution transformer.

Transformer load monitoring (TLM) refers to a program where a utility periodically determines the approximate peak load on each distribution transformer, based on computerized analysis of billing records or based on other system data, and develops a list of potential overloaded transformers. These transformers are then inspected and units showing sign of overloading are replaced with a larger transformer, or have load removed from them by transferring some customers to another transformer. In this way, these overloaded transformers are replaced or are unloaded before they fail, which is typically during a heat wave, when they would otherwise fail in large numbers.

Q., DOES THE COMPANY HAVE A PROGRAM FOR AUTOMATED ESTIMATING OF PEAK DISTRIBUTION TRANSFORMER LOADS?

A. No. As reflected in its response to RAR-RE-11, the Company has no such automated program. The Company is currently in the pilot stages of a program called Wirevision that will have the capability to estimate loading on any node on the distribution system. Presumably, this system could be used to drive a program of replacement of heavily loaded distribution transformers before they fail, but the Company has given no indication that this will be the case.

Q. ARE DISTRIBUTION TRANSFORMER OUTAGES AN INCREASING FACTOR IN ELECTRIC SYSTEM RELIABILITY ON THE ACE DISTRIBUTION SYSTEM?

A. Yes. As reflected in the response to RAR-RE-13, and reproduced below, the number of outages and customer interruptions due to distribution transformer failure have been increasing since 1999, when a very hot summer resulted in large numbers of such failures on the ACE system.

<u>Distribution Transformer Failures on the ACE System</u>

Year	Outages	Approx. Customers Interrupted
1999	794	7,762
2000	84	2,752
2001	77	6,236
2002	261	6,910
2003 (to date)	328	26,249

The Company points out in this referenced response, RAR-RE-13, that its OMS started in June, 2002. As was the case with the SAIFI and CAIDI outage performance statistics, the OMS may be responsible for some increase in 2002 and thereafter, but this does not mean that all of the increases reflected in 2002 and 2003 are driven by OMS implementation and not by actual system performance. The data available indicates that distribution transformer failures are increasing and their effects on customers are sharply increasing. Note that distribution transformer failures sharply increased in 2003 over 2002 levels, despite that fact that the OMS was involved in both years. We note that the Company says that OMS started in June, 2002 in its response to RAR-RE-13. Because most distribution transformer failures are typically heat driven, and such failures occur more often in the summer months, the OMS would be expected to have been involved in a large portion of the 2002 failures, starting in June, typically the beginning of the summer period. We also note that the 2003 data is only for part of the year, through the end of September, 2003 based on Attachment 1 to RAR-RE-13. There is no reason to believe that this trend toward increased outages and customers interrupted has suddenly changed in 2003.

One major reason to monitor transformer loads and to replace such distribution transformers before failure, is the fact that, when these distribution transformers do fail, it is frequently during a heat wave. Then, these transformers tend to fail in large numbers, as was the case in the summer of 1999, which was notable for its heat waves and their impact on system reliability. When these transformers fail in large numbers during periods of high heat, the outages from such failures are prolonged, since there are typically many such failed transformers that then need replacement, thus stretching available Company resources. These prolonged outages occur at times when customer demand for electricity is at its peak, so these failures during periods of heat result in larger lost revenues to the Company than if these units are replaced before they fail.

We note that others have addressed the subject of TLM as follows:

> A good TLM has among the highest payback ratios of any activity related to maintenance and asset management of distribution equipment. Often it pays for itself in a matter of months, by permitting overloaded units to be changed out before high loading levels lead to premature failure. ("Aging Power Delivery Infrastructures", H. Lee Willis, Gregory V. Welch, and Randall R. Schrieber of ABB Power T&D Company Inc., Marcel Decker 2001, pages 357-8).

The Company's lack of any formal program in this area can be expected to continue to contribute to increased outages and customer interruptions in the future. Such a formal program should be implemented. Accordingly, I recommend that the Board order the Company to implement a distribution transformer load management program.

Transformer Testing and Maintenance

Q. DID YOU REVIEW THE COMPANY TESTING AND MAINTENANCE PRACTICES FOR SUBSTATION TRANSFORMERS, GENERATION STEP-UP TRANSFORMERS AND LOAD TAP CHANGERS (A COMPONENT OF LARGE SUBSTATION TRANSFORMERS)?

A. Yes. The Company's response to RAR-RE-14 summarizes changes made in its testing and maintenance practices for such equipment within the last five years. In a number of instances, the Company has reduced the frequency of testing and maintenance on such equipment.

For example, substation power transformers were previously inspected and maintained every five years. In 1999, the Company changed to a six-year cycle for testing and maintaining substation transformers, in part to save money. The Company also represents that lengthening the interval between testing and maintenance can increase reliability, although it gives no explanation as to how this might be possible. In general and contrary to the Company's representations, increasing the interval between testing and maintenance would generally be expected to result in decreased reliability from unexpected failures. Since these pieces of equipment are very expensive and typically have long lead times for the acquisition of replacement units from suppliers, the money saved from less frequent maintenance and testing can typically be wiped out by even one preventable failure of such equipment.

In general, it is expected that such decreases in testing and maintenance will not improve system reliability and could result in a decrease in system reliability from that which resulted from prior practices. The trend of increasing numbers of outages and increasing reliability-related impacts due to equipment failures raises questions about the reliability impacts of decreases in maintenance and testing.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company's current policy of increasing the time intervals between inspections and/or maintenance of major system components, such as substation transformers and breakers, in light of the large costs of such components and in light of the trend of increasing numbers of outages due to equipment failures be modified. The Company should shorten the time between inspections and/or maintenance of major system components. The inspection and maintenance cycle should, at a minimum, be every five years, which was the Company's previous policy.

5. Animal-Related Outages

Q. WHY ARE ANIMAL-RELATED OUTAGES IMPORTANT?

A. As shown in the Company's ASPR for calendar year 2002, animals were the cause of more outage events than any other cause in 2002, as well as for the five previous years. Animals were listed as the cause of more than 22% of the outage events on the Company's system. In addition, such outage events resulted in more than 10% of the Company's customer interruptions in 2002.

Q. HOW DO ANIMALS TYPICALLY CAUSE ELECTRIC SERVICE INTERRUPTIONS?

A. In this part of the country, squirrels tend to be the leading cause of animal-related electric service interruptions, although birds are a common cause as well. The animal typically touches both an energized component and a grounded component. These contact incidents are especially common at overhead distribution transformers on poles. When the animal establishes contact with both energized and grounded components, the electricity flows through the animal causing a short circuit, and causing a fuse or other protective device to operate, thus taking the shorted component out of service and interrupting the supply of electricity to any customers supplied via that component.

Q. HOW CAN THESE TYPES OF OUTAGES BE REDUCED OR PREVENTED?

A. Electric utilities typically install wildlife protection on certain energized components, especially on overhead distribution transformers, which helps prevent animals from contacting the energized component and a grounded component at the same time.

Q. DOES THE COMPANY INSTALL SUCH WILDLIFE PROTECTION ON ITS DISTRIBUTION FACILITIES?

A. The Company installs wildlife protection on new installations of overhead transformers, reclosers, and sectionalizers, and on equipment experiencing animal-related faults. (See RAR-RE-16, Attachment 1) Existing distribution equipment that does not have wildlife protection will not receive such protection until it experiences an animal-caused outage.

While the Company's policy regarding the installation of wildlife protection is basically similar to that of other utilities in the region, the Company's number of animal-related outage events tends to be a larger percentage of total outage events, historically, than what I have typically seen for other utilities. Therefore, there is reason to believe that the current approach will continue to result in a relatively large portion of the Company's outage events being caused by animal-related contacts.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company take a more aggressive approach to the installation of wildlife protection by instituting a program whereby such protection will be installed on all relevant overhead distribution equipment within a given time period. The length of such time period should reflect the degree to which the distribution system still needs such protection and should be no longer than ten years at the longest.

6. Tree-Trimming and Vegetation Management

Q. WHAT IS CONECTIV'S POLICY ON TREE-TRIMMING?

A. According to the December 30, 2002 Operations & Maintenance Plan, Conectiv Power Delivery Electric Substation Transmission and Distribution that was provided as Discovery Response RAR-RE-16, Attachment 1, Conectiv's Distribution Vegetation Management program is a reliability based program consisting of a four-five year inspection/tree-trimming cycle.

In another data response, the Company describes its currently effective transmission and distribution tree-trimming standards as an IVM (integrated vegetation management) program that does not "cycle maintain" the existing vegetative conditions. The Company states that the amount of work required depends on the voltage, number of conductors and construction type of the facility as well as certain characteristics of the vegetation. The Company further states that its work is prioritized by voltage and number of customers served, and that the time interval between various management techniques varies with an average of 4 years between interventions.

There is ample reason to question the approach being taken by the Company to managing its tree trimming activities. As we discussed in the earlier Outage Trends

Analysis section of this testimony, the impacts of faults related to trees has increased greatly in 2002 and the percentage of customer interruptions and of minutes of interruption attributable to tree-related causes increased dramatically in 2002.

Data provided by the Company (RAR-RE-8) shows, by distribution feeder, the last date on which comprehensive tree trimming and spot tree trimming were performed. This data shows that a number of feeders have not been trimmed for over ten years. For example, several feeders last received comprehensive tree trimming in 1990 and have received no spot trimming between that time and the present. Matching up the worst performing circuits for the year 2001 (as shown in RAR-RE-77) with the tree trimming data shows a number of instances of poor performing circuits that had not received tree trimming in many years. For example, in the Pleasantville District, the worst performing circuit was the Elwood feeder from the Egg Harbor substation with a composite SAIFI of 1.698 in 2001. Prior to 2001, the last comprehensive or spot tree trimming occurred in 1991 on that feeder.

Tree trimming expenditures have not increased since 1999 (as shown in the response to RAR-RE-9). Budgeted expenditures for tree trimming in 1999 were $5.6 million and have only increased slightly to $5.9 million in 2003, despite growth of loads and of the number of customers on the Company's system.

Q. WAS CONECTIV'S TREE-TRIMMING PROTOCOL MODIFIED AFTER THE HISTORICALLY HIGH AMOUNTS OF RAINFALL RECEIVED IN THE MID-ATLANTIC REGION DURING THE LATTER PART OF 2002 AND THE FIRST THREE QUARTERS OF 2003?

A. Conectiv stated that the increased vegetative growth caused by abnormal amounts of rainfall did not change which type of vegetation required management. Instead, the Company identified the circuits and concentrated its efforts where vegetation management would alleviate potential problems for the greatest number of customers (RAR-RE-95).

The Company's approach to vegetation management sounds a lot like it allocates available budget so that those areas experiencing the worst tree-related reliability problems get some attention. However, those areas that do not have especially poor reliability performance will apparently have to wait until their reliability deteriorates. While this approach may tend to maximize the reliability impact of the available tree-trimming budgets, it can result in a system-wide deterioration of reliability performance, which is exactly what we are seeing with the Company. The disproportionate increases in the number of customer interruptions and of interruption minutes due to factors related to trees, and in the percentage of customer interruptions and the percentage of interruption minutes due to factors related to trees gives cause for concern over the present and future reliability-related impacts due to causes related to trees.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company's need-based approach to vegetation management be changed 1) to address the intervals of more than four years between trimmings on some feeders and 2) to address the increasing impacts on the number of customer interruptions and on the number of interruption minutes. The Division of Ratepayer Advocate, in recent comments filed with the Board regarding proposed regulations on vegetation management standards, has supported an increase in vegetation inspections to at least once every two years, with trimming performed as needed in order to increase electric system reliability. I recommend that the Board adopt these standards.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.