STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE HONORABLE RICHARD MCGILL, ALJ

I/M/O the Verified Petition of JCP&L	)	
for Review and Approval of Increases in	)	
and Other Adjustments to its Rates and	)	**OAL Docket No. PUC 16310-12N**
Charges for Electric Service, and For	)	
Approval of Other Proposed Tariff	)	**BPU Docket No. ER12111052**
Revisions in Connection Therewith; and	)	
for Approval of an Accelerated	)	
Reliability Enhancement Program	)	
("2012 Base Rate Filing")	)	

DIRECT TESTIMONY OF PETER J. LANZALOTTA
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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Original Filing Date: June 14, 2013
Re-Filed Dated: September 19, 2013

RE-FILED VERSION

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Q. Mr. Lanzalotta, please state your name, position and business address.

A. My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the New Jersey Division of Rate Counsel ("DRC").

Q. Mr. Lanzalotta, please summarize your educational background and recent work experience.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor 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.

I am currently 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. I am a registered professional engineer in the states of Maryland and Connecticut.

In particular, I have been involved with the planning and operation of electric utility systems as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities and government agencies involved in the regulation of electric utilities over a period exceeding thirty years. I have presented expert testimony before the

FERC and before regulatory commissions and other judicial and legislative bodies in 22 states, the District of Columbia, and the Provinces of Alberta and Ontario. My clients have included utilities, state regulatory agencies, state ratepayer advocates, independent power producers, industrial consumers, the United States Government, environmental interest groups, and various city and state government agencies.

A copy of my current resume is included as Exhibit___(PJL-1) and a list of my testimonies is included as Exhibit___(PJL-2).[1]

Q. What is the purpose of your testimony?

A. I was retained to review the Petition filed by Jersey Central Power & Light Company ("JCP&L" or "Company") to increase its retail rates for the distribution of electric energy (the "Petition") as part of DRC's participation in New Jersey Board of Public Utilities ("BPU" or "Board") Docket No. ER12111052 (this "Proceeding") and to comment on the Company's electric service reliability performance and other aspects of this case directly involving reliability. This testimony presents the results of my review.

Q. Please explain how you conducted your analyses.

A. I have reviewed the following information in my investigation:

i. The Company's Petition and Direct Testimony in this Proceeding.

ii. The Company's responses to discovery questions submitted by DRC, the Board Staff, and other intervening parties to this Proceeding.

[1] Exhibit___(PLJ-1) and Exhibit___(PJL-2) as well as all other Exhibits referenced herein are attached to and incorporated by referenced in this testimony.

iii. Various data and information from various reviews of storm performance of New Jersey electric distribution companies in general and of JCP&L in particular that considered various aspects of improving electric service reliability during major storms.

Q. Please summarize your conclusions.

A. My testimony concludes:

JCP&L's reliability performance under major storm conditions is deteriorating, especially where outage duration is concerned.[2]

NJ reliability regulations do not address electric service reliability performance during major storms, and provide incentives which help undermine reliability. Reliability performance during major storms is not included in reliability indices and has no reliability performance targets. In addition, the regulations addressing what happens outside of major storms are also too lax.

More aggressive distribution tree trimming by JCP&L is needed, as well as fewer deferrals of cyclical trimming past their scheduled years. The just-completed corridor-widening initiative was an improvement, but needs to be continued, and strengthened. Reliability performance during Superstorm Sandy makes it clear that more is needed.

While reliability outside of major storm periods has been good, when judged by the minimum reliability levels provided for in the regulations, the priority circuit program is not sufficiently addressing reliability on many of these poorly performing circuits.

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[2] By Motion dated May 30, 2013, Rate Counsel filed an objection to the confidential designation of RCR-REL-32.

A reliability metric that tracks repeated outages affecting smaller groups of customers rather than entire distribution circuits would help address small groups of customers experiencing repeated poor reliability.

Review of Electric Service Reliability performance

Q. What did your review of the Company's electric service reliability performance show?

A. My review of the Company's electric service reliability performance showed i) that the frequency of customer interruptions during major storm events, reflected in the Company's SAIFI (with major events), has increased moderately in recent years, and ii) that the duration of customer interruptions during major storm events, reflected in the Company's CAIDI (with major events), has increased by an average of more than a factor of ten at times during the past two years, over the levels from 2004 – 2010. My review showed that SAIFI and CAIDI (without major events) were well within minimum reliability levels as provided for in the Board's regulations.[3]

Q. How is electric service reliability to customers measured on utility electric distribution systems in New Jersey?

A. Electric service reliability to customers is measured using various metrics or reliability indices. Among the reliability indices defined in the Board's regulations are SAIFI, a

[3] The minimum reliability level is defined as the five year benchmark value plus 1.5 standard deviations.

measure of the average customer electric service outage frequency, and CAIDI, a measure of the average electric outage duration. SAIFI and CAIDI are defined thusly[4]:

> **System average interruption frequency index (SAIFI)** represents the average frequency of sustained interruptions[5] per customer during the reporting period. SAIFI is defined as: total number of sustained customer interruptions[6] per reporting period divided by the total number of electric customers served per reporting period. A SAIFI of 2.0 for a period of a year means that the average electric customer experienced two service interruptions in that year. A higher value for SAIFI reflects lower electric service reliability.

> **Customer average interruption duration index (CAIDI)** represents the average duration in minutes required to restore service to those customers that experienced sustained interruptions during the reporting period. CAIDI is defined as the sum of the total number of customer interruption minutes during the reporting period divided by the total number of sustained customer interruptions during the reporting period. A CAIDI of 120 for a period of a year means that the average electric customer service interruption during that year lasted 120 minutes, or two hours. A higher value for CAIDI reflects lower electric service reliability.

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[4] See N. J. A. C. 14:5 – 1.2.

[5] SAIFI and CAIDI both look only at sustained electric service interruptions, and not at momentary interruptions. Momentary electric service interruptions are limited in duration to the amount of time it takes to restore service via immediate switching operations, up to as much as 5 minutes in duration. If an interruption cannot be classified as momentary, it is considered to be sustained.

[6] An electric distribution circuit with 1,000 electric customers connected to it suffering a complete outage of all its customers is equivalent to 1,000 customer interruptions.

Q. Why are you reviewing these reliability indices?

A. These reliability indices tell us how many electric service interruptions (outages) an EDC's average customer experiences each year (via SAIFI), and these reliability indices tell us how long each such outage lasted on average (via CAIDI). They provide a means to compare an EDC's reliability performance with itself over time and see if reliability is improving or getting worse. If the Company's SAIFI this year is higher than last year's, then we know that there were more customer service interruptions this year than last year. Similarly, if the Company's CAIDI this year is higher than last year's, then we know that customer interruptions were lasting longer this year than they did last year. This is especially important when there are questions being raised about an EDC's electric service reliability.

Q. Are all electric service interruptions included in the calculation of these reliability indices, even if the interruptions occur during and are the result of a major storm?

A. The Board's regulations specify that EDCs exclude all customer interruption data during major events from the calculation of these reliability indices.[7] My testimony looks both at reliability indices calculated according to the Board's regulations, and at reliability indices that include data from major events, in order to try to get a more complete picture of the electric service reliability being experienced by the Company's electric customers.

Weather is a major driver of electric service interruptions. Storms with intense wind, ice, and/or snow conditions can cause greatly increased numbers of customer electric service

[7] N. J. A. C. 14:5-1.2 Definitions, See part 1 under the definition of "Major Event". New Jersey defines major events as events beyond the control of the Company which affect at least 10% of an EDC's electric customers in any one service area or operating area. JCP&L has two such areas: northern and central.

interruptions and can cause increased duration of those service interruptions as well. Because weather varies from year to year, some weather-related customer outage data may be withheld from the calculation of some of these electric service reliability indices in an attempt to develop electric service reliability indices that reflect the inherent reliability of the electric system as designed and maintained, without any influence from extraordinary weather events, or other events deemed beyond the control of the Company. This is sometimes referred to as “blue sky” conditions[8].

Q Why are you looking at reliability indices that include major events if the Board’s regulations allow the EDCs to exclude major events from reported reliability indices?

The reliability indices that include all customer interruption data, including those that happen during major events, are important for several reasons.

First, they show what electric customers are actually experiencing in the way of electric service reliability. It makes little sense to judge a utility’s electric service reliability performance only by looking at “blue sky” performance when such conditions reflect a decreasing share of customers’ outage experiences. Customers, increasingly, are more affected by what happens to their electric service during major ice, snow, wind, and/or lightning storms, especially when they lose electric power for days at a time. There’s little point in making believe that these weather-related service interruptions are not happening and do not need to be addressed.

[8] While “blue sky” conditions typically include minor storms, they typically exclude major weather events.

Second, the frequency of these weather-related major outage events has increased as of late. In the last several years, the eastern U. S. has seen an increase in electric service interruptions due to major weather problems, including ice, heavy snow, high winds, and intense lightning. In the past several years, the Company's system has experienced major storms of increasing impact. Table 1 below lists the number of days each year on which the Company experienced a major event and excluded outage data from their reported SAIFI and CAIDI.

Table 1[9]

Year	MEDs[10]
2004	4
2005	9
2006	13
2007	10
2008	40
2009	22
2010	56
2011	62

Note that, by 2011, more than one day in six[11] during the entire year was a major event day. This represents too big a piece of the year during which to ignore the electric system's reliability performance, and then claim that reliability is fine.

Third, there seems to be a growing disconnect between how the Company evaluates its reliability performance (with major events removed), and how its customers evaluate this

9 Data taken from Figure III.3 from Cummings Direct Testimony, page 22.
10 "MED" means major event days.
11 One-sixth of 365 equals 60.83.

performance (with all outages in play). In this rate increase filing, the Company touts its reliability performance as steadily improving, if we ignore major storms. However, its reliability performance including major storms has not been steadily improving. Instead, reliability performance during major storms has deteriorated to the point that it is becoming increasingly difficult to ignore such performance.

Q. How has the Company's SAIFI electric service reliability performance been over the past nine years?

A. Table 2 below lists SAIFI data, with and without major events, for the past nine years, for the Company and for each of its two operating areas.

Table 2

SAIFI	Without Major Events			With Major Events		
	Northern	Central	Total Co.	Northern	Central	Total Co.
2004	1.60	1.19	1.36	1.77	1.24	1.47
2005	1.44	1.24	1.32	1.51	1.36	1.43
2006	1.53	1.31	1.40	1.90	1.63	1.75
2007	1.37	1.14	1.24	1.43	1.34	1.38
2008	1.12	0.99	1.05	1.73	1.40	1.54
2009	1.04	0.97	1.00	1.32	1.12	1.20
2010	1.25	1.00	1.11	1.76	1.87	1.83
2011	1.30	0.77	0.99	3.19	1.94	2.46
2012	1.20	1.04	1.11	2.43	3.16	2.85
Average	1.32	1.07	1.18	1.89	1.67	1.77
Benchmark	1.44	1.26				
Minimum	1.63	1.50				

The Company's two operating areas, northern and central, are separate, non-contiguous, and each has distinct characteristics. The northern area, headquartered in Morristown, New Jersey, includes all or portions of the counties of Essex, Hunterdon, Mercer, Morris, Passaic, Somerset, Sussex, Union and Warren. The central area, headquartered in Red Bank, New Jersey, includes all or portions of the counties of Burlington, Mercer, Middlesex, Monmouth, and Ocean.[12] Because each operating area has distinct characteristics, the Company reports its reliability data separately for each.

SAIFI reflects the number of customer interruptions per customer per year. Looking, first, at the northern area, its SAIFI (without major events) starts at 1.60 interruptions per year in 2004, and an average value of 1.52 interruptions per year for the three years 2004-2006, before dropping to as low as 1.04 interruptions per year in 2009. Since then, the

[12] 2011 Annual System Performance Report, pp. 5.

northern area's SAIFI (without major events) has increased back into the range from 1.2 to 1.3 interruptions per year. These levels compare favorably to the northern area's benchmark[13] standard of 1.44 interruptions per year and the minimum reliability level[14] of 1.63 interruptions per year. The average northern area SAIFI (without major events) for this nine year period was 1.32 interruptions per year.

The central area's SAIFI (without major events) is lower than the SAIFI (without major events) for the northern area in every year from 2004 through 2012. The central area's SAIFI (without major events) varied from 1.14 to 1.31 interruptions during the years 2004 - 2007, before dropping to a level close to or below 1.00 for the period 2008 – 2012. These levels also compare favorably to the central area's benchmark standard of 1.26 interruptions per year and the minimum reliability level of 1.5 interruptions per year. The average central area SAIFI (without major events) for this nine year period was 1.07 interruptions per year.

Total Company SAIFI (without major events) starts at 1.36 interruptions per year in 2004, dropping to 1.24 interruptions in 2007, and further dropping to a range from 0.99 interruptions to 1.11 interruptions over the period 2008 through 2012. While the SAIFI (without major events) for the total Company shows improvement over the period 2004 through 2012, this tends to mask the fact that the northern area is consistently higher, as much as 69% higher in 2011, and about 23% higher on average over the period from 2004 through 2012. This difference in "blue-sky" reliability implies that the northern

[13] The benchmark standard is defined as the average index value for the five years from 2002-2006. N. J. A. C. 14:5-8.9.

area, and its electric system, has characteristics that result in more frequent occurrences of customer interruptions.

The right side of Table 2 shows the SAIFI performance of the Company and its two operating areas, but this time with major events included. The SAIFIs (with major events) tend to be more volatile from year to year, reflecting varying weather conditions and the performance of the electric system under those varying conditions.

The northern area SAIFI (with major events) starts in 2004 at 1.77 interruptions per year. Over the next six years, 2005 – 2010, the northern area SAIFI (with major events) varies up and down in alternating years at values between 1.32 and 1.76 (except for a value of 1.90 in 2006). Then, in 2011, the northern area SAIFI (with major events) increased to 3.19, an increase of over 80 % over the previous year, and a level that was over 67% higher than the next highest annual value in the seven preceding years. In 2012, the northern area SAIFI (with major events) decreased to 2.43 interruptions per year, a level that was still higher than in any of the eight previous years, save 2011.

The central area SAIFI (with major events) in Table 2 starts in 2004 at 1.24 interruptions per year and increases over the next two years, up to a value of 1.63 in 2006. The next years, 2007 and 2008, have a central area SAIFI (with major events) values of 1.34 and 1.40, respectively, before decreasing to its nine-year low of 1.12 interruptions per year in 2009. After 2009, the central area SAIFI (with major events) increases to new nine-year highs in each of the next three years, with 1.87 interruptions per year in 2010, 1.94 interruptions in 2011, and, finally, 3.16 interruptions per year in 2012. In two of these three years, 2010 and 2012, the central area has a higher SAIFI (with major events) than the northern area, the only times that happens in the entire nine years depicted in Table 2.

The total Company SAIFI (with major events) starts at 1.47 interruptions per year in 2004, and varies over the next six years at levels that range between 1.20 to1.83. In 2011, the total Company SAIFI (with major events) increases to 2.46 interruptions per year, followed by another increase in 2012 to 2.85 interruptions.

The increases in the Company's SAIFI indices (with major events), relative to the SAIFI indices (without major events), mean that the majority of customer interruptions are now occurring during major events, and are subsequently considered "off the books" by the Company for reliability evaluation and reporting purposes, whereas, in the past, the majority of customer interruptions occurred during normal blue sky conditions and were included in the Company's reported reliability performance. This is shown in Table 3 below, which shows the ratio of the Company's SAIFIs (with major events) to the Company's SAIFIs (without major events).

Table 3

SAIFI	Ratio of With ME to Without ME[15]		
	Northern	Central	Total Co.
2004	1.11	1.04	1.08
2005	1.05	1.10	1.08
2006	1.24	1.24	1.25
2007	1.04	1.18	1.11
2008	1.54	1.41	1.47
2009	1.27	1.15	1.20
2010	1.41	1.87	1.65
2011	2.45	2.52	2.48
2012	2.03	3.04	2.57
Average	1.44	1.56	1.50

Table 3 shows that the ratio of SAIFIs (with major events) to the SAIFIs (without major events) was in the range from 1.04 to 1.25 in the years 2004 – 2007. A value of 1.25 means that the major-event-related customer interruptions were equal to 25% of the blue-sky customer interruptions. The low ratio values in this time frame indicate that the majority of customer interruptions occurred outside of major events. In 2008, these ratios increased to levels in the 1.41 to 1.54 range, indicating that major event customer interruptions were equal to 41% to 54% of the customer interruptions that occurred during blue-sky conditions. In 2009, these ratios declined, only to start increasing again in 2010, to a range from 1.41 to 1.87, and finally, in 2011 and 2012, to levels above 2.00 and as high as 3.04. At a level of 2.00, this ratio means that there are as many customer interruptions occurring during major events as there are during blue sky conditions. At ratio levels greater than 2.00, there are more customer interruptions occurring during major events than are occurring outside of these events. At a ratio level of greater than

[15] "ME" means Major Events.

3.00, as occurred in 2012 for the central area, more than twice as many customer interruptions occurred during major events in 2012 in the central area than occurred during blue sky conditions. The SAIFI and CAIDI index reporting, benchmark standards, and minimum reliability levels specified in the N. J. A. C., which exclude major events, are addressing less than one-third of the total customer interruptions that occurred in the central area in 2012. This shows that the Board should consider the Company's annual reliability data both with and without the inclusion of major events. By looking at major events as isolated incidents, the Board is not getting a complete picture of the overall reliability of the Company. In order to do this the Company should report CAIDIs and SAIFIs with and without major storms annually in their annual systems performace report. Currently, the Company does not report the CAIDI and SAIFI numbers including major events in its annual system report.

Q. Please describe the Company's CAIDI electric service reliability performance over the period 2004 – 2012.

A. Table 4 below lists CAIDI data, with and without major events, for the past nine years, for the Company and for each of its two operating areas.

Table 4

CAIDI	Without Major Events			With Major Events		
	Northern	Central	Total Co.	Northern	Central	Total Co.
2004	136	88	112	166	88	128
2005	154	114	132	158	120	137
2006	127	112	119	176	159	167
2007	119	72	94	119	141	132
2008	104	86	94	239	97	164
2009	133	81	104	158	91	122
2010	133	107	119	196	255	231
2011	132	100	117	1,662	867	1,298
2012	130	100	114	3,815	2,933	3,248
Average	130	96	112	743	528	625
Benchmark	158	110				
Minimum	199	132				

CAIDI reflects the duration in minutes of the average customer interruption. Looking, first, at the northern area, CAIDI (without major events) starts in 2004 at 136 minutes per customer interruption, and increases to 154 minutes in 2005, before decreasing over the next three years down to a level 104 minutes in 2008. For the remaining four years, 2009 – 2012, the northern area CAIDI (without major events) went back up to a level of 133 minutes per customer interruption in 2009, and stayed in the range from 130 to 133 minutes for the remained of that period, ending at 130 minutes in 2012. These levels compare favorably with the benchmark standard for the northern area CAIDI (without major events) of 158 minutes and the minimum reliability level of 199 minutes. The nine year average CAIDI (without major events) for the northern area is 130 minutes per customer interruption.

The CAIDI (without major events) for the central area starts at a level of 88 minutes per customer interruption in 2004, increases to the range from 112 minutes to 114 minutes in

2005 and 2006, before decreasing down to the range from 72 minutes to 86 minutes in 2007-2009. Finally, in 2010 – 2012, the central area CAIDI (without major events) increases to values in the range from 100 to 107 minutes, ending at 100 minutes in 2012. This performance compares favorably with the the benchmark standard for the central area CAIDI (without major events) of 110 minutes and the minimum reliability level of 132 minutes. The nine year average CAIDI (without major events) for the central area is 96 minutes per customer interruption.

Total Company CAIDI (without major events) starts at 112 minutes per customer interruption in 2004, increasing to 132 minutes in 2005, decreasing back to 119 minutes in 2006, and further decreasing to a level of 94 minutes per customer interruption in 2007 and 2008. For the period 2009 – 2012, the total Company CAIDI (without major events) varies in range between 104 minutes and 119 minutes, with the last four years in the range from 112 to 119 minutes, and ending up in 2012 at 114 minutes. While the CAIDI (without major events) for the total Company shows limited improvement over the period 2004 through 2012, the relationship between the two operating areas continues to be divergent, with the northern area CAIDI (without major events) consistently higher, averaging about 35% higher on average over the period from 2004 through 2012. This difference in "blue-sky" reliability implies that the northern area, its electric system, and its restoration resources are such that customer interruptions tend to last longer in the northern area than in the central area.

The Company's CAIDI performance (with major events) has significantly deteriorated in recent years. The northern area CAIDI (with major events) varies between the values of 119 minutes (almost two hours) per customer interruption and 239 minutes (almost 4 hours) per customer interruption in the period from 2004 to 2010. However, in 2011, the northern area CAIDI (with major events) increases to 1,662 minutes (27.7 hours) per customer interruption, an increase by almost a factor of seven times over the highest value in the preceding seven years. And, 2012 was even worse, with the northern area CAIDI (with major events) increasing further to 3,815 minutes (63.6 hours, or more than 2.5 days) per customer interruption, an increase over the 2011 level, which itself was incredibly high, by a factor of about 2.3 times.

The central area CAIDI (with major events) varies in the range from 88 minutes per customer interruption to 159 minutes per customer interruption in the period from 2004 to 2009. In 2010, the central area CAIDI (with major events) increased to 255 minutes, a level higher than the previous high value in the 2004 – 2009 period by 60%. This trend continued in 2011, when the central area CAIDI (with major events) increased to 867 minutes (14.45 hours) per customer interruption, an increase by a factor of 3.4 times over the 2010 value. In 2012, this remarkable trend continued even further, when the central area CAIDI (with major events) increased further, to a level of 2,933 minutes (about 49 hours, or more than 2 days) per customer interruption, an increase by more than a factor of 3.3 times over the elevated 2011 value.

As was the case with the SAIFI indices, the increases in the Company's CAIDI indices (with major events), relative to the CAIDI indices (without major events), mean that the majority of customer interruption minutes are now occurring during major events, and are subsequently considered "off the books" by the Company for reliability evaluation and reporting purposes. In the past, the majority of customer interruption minutes occurred during normal blue sky conditions in most years and were included in the Company's reported reliability performance. This is shown in Table 5 below, which shows the ratio of the Company's CAIDIs (with major events) to the Company's CAIDIs (without major events).

Table 5

CAIDI	Ratio of With ME to Without ME		
	Northern	Central	Total Co.
2004	1.22	1.00	1.14
2005	1.03	1.05	1.04
2006	1.39	1.42	1.40
2007	1.00	1.96	1.40
2008	2.30	1.13	1.74
2009	1.19	1.12	1.17
2010	1.47	2.38	1.94
2011	12.59	8.67	11.09
2012	29.35	29.33	28.49
Average	5.73	5.52	5.60

In the years 2004 to 2010, most of the ratios vary between the range from 1.00 to 2.00. A value of 1.40, for example, means that the minutes per customer interruption including major events was 40 % higher than the minutes per customer interruption excluding major events. In 2011, this ratio increases to 11.09 for the total Company, which indicates that the minutes per customer interruption, including major events, was more than 11 times higher than the minutes per customer interruption excluding major events. In 2012, this ratio increases again to 28.49 for the total Company, which indicates that the outage duration (minutes per customer interruption), including major events, was more than 28 times higher than the outage duration (minutes per customer interruption) excluding major events.

In conclusion, the Company's reliability performance during major storms has resulted in increasing long outage restoration times and an increasing portion of customers' outage experience occurring during these events which are excluded from the Company's reliability indices and from the Company's reliability benchmarks and minimum reliability levels.

Q. The Company takes the position that electric customers have increased their reliability expectations. Please address.

A. Company witness Mader states that the accelerated reliability enhancement program ("AREP") was proposed in this proceeding in order to address the increasing expectations of customers for higher service levels, following the two major storm events in 2011.[16] He also attributes such calls for higher service levels to the administration and to the BPU. Actually, given the dramatic decline, even collapse, of the Company's electric service reliability during weather-related major events over the past several years, especially where outage durations are concerned, it is likely that customers expect the level of reliability they had before these declines took place. This is less a case of customers increasing their expectations, than it is a case of customers refusing to lower their expectations in line with the Company's storm performance.

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[16] Exhibit JC-2, Direct Testimony of Mark A. Mader, pp.17, lines 14-21.

Service Reliability Regulations

Q. Are the current regulations regarding electric service reliability helping to maintain or improve electric service reliability?

A. No. As discussed in the prior pages, the current regulations fail to address reliability performance during major storms. Furthermore, the standards the current regulations set for reliability performance for periods outside major storms are outdated and so flexible that JCP&L could have a significant decline in its reliability performance, excluding major storm events, and still meet the statutory minimum performance levels.

Q. Are there measures of electric service reliability that should be considered in addition to what is currently required?

A. Yes. As discussed above, reliability performance during major storms needs to be considered as a measure of electric service reliability. At a minimum, the Board should require the EDCs to report their annual reliability metrics, SAIFI and CAIDI, with and without major events included. But, more than just reporting is needed at this point.

Next, the Board should consider tightening up, or otherwise changing, the determination of when a major event may be excluded from an EDCs reliability indices used to determine minimum reliability levels. When more than 50-60 days per year are excludable from reliability indices because of major events, it's clear that the definition of major events is functioning much differently today from when it was originally instituted.

One of the concerns about using the criterion of 10% of electric customers in an area being out of service to determine major events, within the current reliability regulations, is that this criterion makes larger outages less onerous to the EDCs' reported reliability performance, thus encouraging electric system practices that make such larger outages more likely. If a storm interrupts electric service to less than 10% of an area's electric customers, then the EDC has to count every customer interruption in its SAIDI and CAIDI. If, however, a storm interrupts more than 10% of an area's customers, then the EDC gets to ignore all the resulting customer interruptions in that area, and more, when it reports its SAIFI and CAIDI. This perverse incentive encourages system practices that are not effective at preventing electric service interruptions during storm conditions, even while potentially helping improve reliability under blue-sky conditions.

This incentive is magnified by the fact that, under today's regulations, if there is a major event occurring in one service area of an EDC, then it can exclude customer interruptions occurring anywhere and everywhere in the Company's service territory from its SAIFI and CAIDI calculations.[17] In the case of the Company, its two service areas are non-contiguous and may not experience the same major weather events at the same time. While major weather-related outages in one operating area may require resources from other company operating areas to assist in service restoration, such outages should not be a license to neglect service restoration in other areas. The current system gives EDCs incentives not to maximize the storm resiliency of their distribution systems, in the hopes of meeting the 10% customer-out threshold more readily, thereby being able to exclude

[17] N. J. A. C. 14:5-1.2 Definitions, See part 1 under the definition of "Major Event".

customer interruptions occurring over their entire system during these storms from their SAIFI and CAIDI calculations.

EDCs are also permitted to request permission to treat periods when they are supplying "mutual assistance" resources to other utilities with storm trouble as if there were a major event of their own systems for purposes of calculation SAIFI and CAIDI.[18] While this practice avoids discouraging the EDCs from providing mutual assistance resources to other utilities in trouble, it potentially contributes to the situation in 2011 where one day in six has major event status.

In sum, I recommend that the Board's standard used to declare a major event should be tightened up. In addition, the Board should establish for each EDC a reliability standard that includes major events based on SAIFI, CAIDI, and/or some other measure of reliability performance.

Q. Have you any other concerns regarding the Benchmark and Minimum Reliability levels provided for in the Board regulations?

A. Yes. The benchmark standards and minimum reliability levels provided for in the regulations also have some serious shortcomings, other than the fact that they omit customer interruptions during major events. As can be seen from my testimony above, the minimum reliability levels provided for SAIFI and CAIDI (without major events) are increasingly marginalized because JCP&L's performance in these metrics is achieved, in part, by declaring an increasing number of days each year as major events.

[18] N. J. A. C. 14:5-1.2 Definitions, See part 4 under the definition of "Major Event".

But, beyond this, the benchmark standards and minimum reliability levels for JCP&L, which exclude major event performance, have increasingly become a non-issue in part because they are so far out of touch with the Company's actual performance. Reliability benchmark standards should reflect either more recent historical performance, at a minimum, or they should reflect a reliability target sought after by the Board, rather than just a level of historical performance.

The margin for variation between the benchmark standard, which reflects the target level of performance, and the minimum reliability standard, is too one-sided in the EDC's favor. This minimum level of reliability is taken as 1.5 standard deviations ("STD") from the five year average (2003 – 2006) that is used as the benchmark. One problem with this approach is that the EDC is permitted to always be 1.5 STD <u>above</u> the benchmark. The target should, at the least, be to maintain average reliability performance at the benchmark, not at a level above (less reliable) than the benchmark. Some year to year variation in reliability index performance is normal, but over time, this variation should average out, if desired reliability levels are really being maintained.

The Board should consider making the Benchmark level of reliability the measure of adequate service or should consider setting a reliability standard based on some target level determined by the Board, not by an EDC's past performance.

Cummings Testimony

Q. The Company presents the Direct Testimony of Jeffrey Cummings, a consultant who opines on a variety of subjects, including the desirability of planning based on outage data that excludes major events and the similarities between the Company

and other utilities in terms of spending, staffing, storm performance, and other measures. Please comment.

A. Company witness Cummings opines that excluding major storms from reliability performance reviews helps prevent "distortions" in utility planning and capital spending that would otherwise be driven by the inclusion of weather events, over which the utilities have no control, in the reliability review and planning process. While the Company has no control over whether storms occur or how strong they are, it does have control over how well prepared the electric system, and its surrounding vegetation, are to deal with those storms. If distribution tree-trimming is deferred, or if tree canopies are not aggressively trimmed as part of the Company's normal vegetation management cycle, or if off-row problem trees are not aggressively dealt with as part of the Company's normal vegetation management cycle, it should come as no surprise when major storms cause major tree-related damage to overhead distribution systems. JCP&L's storm-related reliability performance, especially regarding outage duration, has deteriorated badly in the past two years. The performance of utility planning and allocation of capital spending with the perspective that the major weather events driving the Company's deteriorating reliability performance are distortions to be ignored has helped enable this deterioration.

Mr. Cummings introduces several "peer" groups of utilities with which he compares the Company in a number of ways, including system design and maintenance practices, spending levels, staffing levels, storm restoration performance, and the like. However, I note that there are a number of electric utilities among his peer groups that have had major storm experiences similar to that of the Company in 2011. On page 59 of his

Direct Testimony, Mr. Cummings lists[19] the customer service restoration percentages by day of eight electric utilities from his various peer groups, plus the Company, during the October 31 (2011) Snow Storm. Of the nine utilities listed, seven had customers out of service for six days or more, including the Company.

Several of the utilities in these peer groups have been criticized by their state commissions for poor storm performance in the past several years. The Maryland Public Service Commission imposed a $1 million fine on Potomac Electric Power Company (MD)[20] for its poor storm performance in 2011 and the system maintenance conditions contributing to that performance. The Massachusetts Department of Public Utilities fined Western Massachusetts Electric Company[21] $2 million for their handling of the October 29, 2011 snowstorm and NStar Electric and Gas $4.1 million for their handling of both Tropical Storm Irene and the October 2011 snowstorm. The Connecticut Public Utility Regulatory Authority issued a decision in August 2012 that found that Connecticut Light & Power Company's preparation for, its response to, and its communications during the 2011 storms was deficient and inadequate, and specified that certain penalties which could be considered during its next rate case.[22]

This only highlights the fact that the Company was not alone in its poor storm performance in 2011. It does not make the rapidly lengthening customer outage durations experienced by the Company's customers in 2011 during major storms any more acceptable.

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[19] In Figure III.29 on page 59.
[20] See Maryland PSC Case No. 9240 at http://webapp.psc.state.md.us/Intranet/home.cfm.
[21] D. P. U. Docket No. 11-119-C.
[22] See Northeast Utilities Form 10 K for the period ended December 31, 2012.

Mr. Cummings highlights[23] the fact that the Company experienced heavy damage from the major storms in 2011 relative to many of the utilities in the peer groups. However, this highlights the fact that the Company's tree trimming practices left the Company vulnerable to greatly increased tree-related outages, which manifested itself especially during the October Snow Storm. This storm, which featured heavy wet snow, in combination with most trees still retaining foliage, resulted in large numbers of downed tree limbs, branches, and power lines. The data available showed that the Company had more trouble locations, approximately 25,000, than any other utility in the state, and perhaps more than all the other state utilities combined.[24] This storm accentuated the reliability effects of the Company's tree trimming practices, which results in more branches in close proximity to and over top of distribution circuit conductors. When these branches, with their foliage still remaining, got loaded down with wet, heavy snow and fell, the resulting damage to the electric system was difficult to repair in a timely fashion.

Tree Trimming

Q. Why is vegetation management important to the Company's reliability performance during major storms?

A. The numerical data in Table 6, below, summarizes tree-related outage causes, outage duration, and total outage data for Hurricane Irene, the October 2011 Snowstorm, and Hurricane Sandy as reported by the Company in its discovery responses.

[23] See Figure III.23, pp. 53 from Mr. Cummings Direct testimony for Hurricane Irene, and Figure III.28, pp. 58 for the October 31 Snow Storm.

[24] See "Hurricane Irene Electric Response Report" by the BPU Staff, December 14, 2011, pp. 25.

Table 6

Tree -Related Outage In Major Events	Customer	Customer	Hours
(2011 - 2012)	Interruptions	Interruption	Per
		Hours	Interruption
Hurricane Irene (2011)			
Trees - Not Preventable	243,844	9,399,467	
Trees - Preventable	11,989	368,292	
Trees - Total	255,833	9,767,759	38.2
Total Storm	742,598	28,311,989	
Tree Percentage	34.5%	34.5%	
October 2011 Snowstorm			
Trees - Not Preventable	249,648	14,638,477	
Trees - Preventable	7,898	451,923	
Trees - Total	257,546	15,090,400	58.6
Total Storm	451,691	25,452,497	
Tree Percentage	57.0%	59.3%	
Hurricane Sandy (2012)			
Trees - Not Preventable	266,502	29,040,299	
Trees - Preventable	14,449	939,087	
Trees - Total	280,951	29,979,386	106.7
Total Storm	1,320,656	132,840,514	
Tree Percentage	21.3%	22.6%	

In Hurricane Irene, tree-related faults caused 34.5 % of customer interruptions and customer interruption hours, and were the largest outage cause category, causing more than 9.7 million customer interruption hours. Each tree-related customer interruption lasted an average of 38.2 hours.

In the October 2011 Snowstorm, tree-related faults caused 57% of customer interruptions and 59.3% of customer interruption hours, and were the largest outage cause category, causing more than 15 million customer interruption hours. Each tree-related customer interruption lasted an average of 58.6 hours.

In Hurricane Sandy, tree-related faults caused 21.3% of customer interruptions and 22.6% of customer interruption hours, and were the largest outage cause category after the categories of "unknown" and "wind", causing more than 29.9 million customer interruption hours. Each tree-related customer interruption lasted an average of 106.7 hours.

In addition to trees, wind, and unknown as substantial causes of outages during storms, equipment failure is also a substantial contributor. The leading equipment-related cause of customer outages is reported to be overhead primary conductors.[25]

Q. Table 6 above uses the terms "preventable" and non-preventable" when describing tree-related customer service interruptions. Do these descriptions accurately describe the nature of the tree-related interruptions they are attempting to describe?

A. No, these descriptions are artificial constructs that are not accurate in the impression they attempt to convey. Company witness Ralph Hilmer notes[26] that the term "preventable"…"is a term of art that refers to outages caused by trees within the right-of-way or trim corridor. It does not mean or in any way imply that JCP&L's activities in connection with its cyclical vegetation management programs were deficient or that a

[25] Schumaker & Company Audit Report, pp 311, Finding IX-9.

[26] See Direct Testimony of Ralph Hillmer, pp.8, lines 9-14.

particular 'preventable' outage could or should have been avoided through implementation of these accepted vegetation management practices."

By the same logic, the term "unpreventable" refers to tree-related faults from limbs or tree trunks located outside the normal trimming zone, including branches from the canopy located directly over the wires but outside the normal 15 foot trim zone.[27] However, it should come as no surprise when branches located directly above the wires break and fall into the wires during snow, ice or heavy wind conditions. These are unpreventable only in the sense that the Company chooses not to try to prevent them by choosing to restrict their trimming of the canopy.

Q. Please discuss the Company's vegetation management program for its distribution system.

A. Under its regular program, the Company inspects its distribution circuits on a four-year cycle, trimming these as needed to a clearance equal to four years of growth. Trimming may be deferred as needed.

The JCP&L distribution system has 12,012.6 overhead miles of circuits.[28] On a balanced four-year cycle, about 3,003 miles would nominally be inspected and trimmed every year. Table 7 below summarizes miles "trimmed" and the cost[29] of such trimming, as provided in response to RCR-REL-5, and the cost per mile of such trimming as

[27] See Direct Testimony of Ralph Hillmer, pp.8, lines 15-21..
[28] See Company's response to RCR-REL-2 (b). This response "updates" the milage number used in Mr. Hillmer's Direct Testimony.
[29] Both expensed and capitalized costs.

calculated from this data. (SAIDI data in table below is confidential)

Table 7

	JCP&L Distribution				
Year	Miles Trim	Cost ($)	Cost/Mile ($)	SAIDI	Miles
				(with ME)	Deferred
2005	3,073	21,438,756	6,976	137	
2006	1,784	10,201,663	5,718	167	
2007	2,842	12,503,253	4,399	132	
2008	3,923	15,232,972	3,883	164	1,152
2009	3,382	12,761,529	3,773	122	1,135
2010	2,945	13,668,141	4,641	231	902
2011	2,925	23,462,674	8,021	1,298	416
2012	4,001	26,760,999	6,689	3,248	
Ave.	3,109	17,003,748	5,469		

While a certain amount of annual variability in the miles trimmed is normal, several of the years exhibit somewhat more variability than what might be expected, especially 2006, which had about 60% of nominal yearly trimming, 2008, which had 130% of nominal yearly trimming, and 2012, with 133% of nominal annual trimming. The cost per mile of trimming exhibits ever more variability, ranging from a high of around $8,000 per mile to low values around $3,800 per mile. This variability raises questions about the consistency of the quality of tree trimming being provided, and about how much trimming, or priority tree removal, is being performed for those per-mile costs. Note that the years 2007, 2008, 2009, and 2010 have per mile trimming costs in the range from $3,773 to $4,641, considerably below the other years, which range from $5,718 to $8,021, and considerably below the eight year average trimming cost of $5,469 per mile.

Note, also, that after four years of this low-cost tree-trimming, the Company's reliability performance during storms, as reflected in the SAIFI and CAIDI data previously discussed, deteriorated sharply. (The SAIDI index for the total Company (with major events) is also shown in Table 7.) The BPU's vegetation management standards for distribution facilities should be more definitive, with certain minimum standards beyond a requirement to inspect distribution circuits every so many years, and to trim as necessary.

It is difficult to place a lot of faith in some of the Company's tree-trimming numbers. The mileage trimmed annually in Table 7 reflects the planned trimming for each year, without reflecting that some mileage in some years was deferred to later years for a variety of reasons.[30] Miles of deferred trimming for selected years are also shown in Table 7 in the year from which trimming was deferred.[31]

For example, the recent management audit of JCP&L found that 1,152 miles of distribution trimming in 2009 had been deferred to longer than a four-year cycle, allegedly on distribution circuits with good reliability performance.[32] In addition, there were other deferrals of scheduled tree trimming. JCP&L's response to RCR-REL-90 indicates that 444 miles of northern area distribution trimming and 691 miles of central area distribution trimming were deferred from 2009 into 2010 or 2011. JCP&L's response to RCR-REL-88 indicates that trimming on 657 distribution miles in the northern area and 245 distribution miles in the central area were deferred from 2010 to

[30] See Note on Attachment 1 to Company's response to RCR-REL-5.
[31] The value for 2008 was estimated. These miles were reported trimmed in 2009 after more than a four-year interval from the prior trim. Some of these 2008 miles may have been deferred from even earlier years.
[32] Schumaker & Company Audit Of JCP&L, June 2011, pp310.

2011. JCP&L's response to RCR-REL-89 indicates that distribution tree trimming on 255 northern area miles and on 161 central area miles were deferred from 2011 into 2012.

Deferring tree trimming on circuits with no recent tree-related reliability problems is one way to reduce tree trimming expenses. There were other reasons for the deferrals as well, including the Company's distribution corridor widening initiative, started in 2009, and the need to repair the system after the major weather events experienced in recent years.

Deferring tree trimming, for whatever reason, tends to make the distribution system more vulnerable to major weather events. This is because trees along distribution circuits are trimmed by JCP&L to provide four years growth worth of clearance, typically 15 feet,[33] between trees and wires. After four years, the limbs and branches to the sides of the wires on a distribution circuit will have grown into close proximity with or even past, the wires, while any limbs overhanging the wires, in the tree canopy, will have grown longer, reaching further over the wires[34]. Now, this may not make much of a difference under normal, blue-sky, conditions. But, under conditions with high winds, ice, or heavy snow, this increased proximity between branches and wires and increased canopy coverage will translate into increased system damage and customer interruptions. Such deferrals increase the likelihood of tree-related customer interruptions during storms. If the Company is tree trimming four-years growth of clearance, then is should be trimming every circuit every four years.

[33] See Direct testimony of Ralph Hilmer, pp 8, lines 7-9.

[34] If limbs have been trimmed so as to remove the tree canopy over the wires, then these limbs will have grown into the space above the wires.

In addition to the deferrals of distribution trimming beyond the four years of clearance to which its distribution circuits are cleared, the Company's normal tree trimming practices undercut storm reliability in another way. The Company's normal trimming practices calls for the tree branches located over the top of distribution circuits, called the canopy, to be trimmed to a clearance of fifteen feet, and for any dead or structurally weak limbs to be removed from the canopy. But, subject to these limitations, the tree canopy is permitted to remain above the distribution circuit wires under the Company's normal tree-trimming practices. It should surprise no one that the October 2011 snow storm, which struck while foliage remained on the trees, was so destructive. With a tree canopy in place over many distribution circuits, these branches were subject to being weighted down with snow until they broke and fell down onto the wires. In high winds, as well, branches from the canopy are subject to breakage, with a similar result. While the Company considers such tree-related faults to be "non-preventable", it is questionable just how accurate such a designation is for tree-related faults associated with leaving the tree canopy in place above distribution circuit wires.

The Company has been implementing a corridor-widening initiative, starting in 2009, and running for four years. Under this initiative, the Company has tried to widen transmission distribution trimming corridors, where practical, and remove selected "overhangs" on selected circuits. The Company estimated, in its response to RCR-REL-74, that less than 25% of the distribution circuit miles have received corridor widening, and not all overhanging branches were necessarily removed over these circuit portions. I note that this initiative does not mention addressing priority trees. I also note that the program is over, and the Company will no longer pursue this initiative.

In order to address its declining storm performance, the Company should implement regular, cyclical corridor widening and regular cyclical full canopy removal over at least the most critical backbone portions of its distribution circuits, if not more.

Q. Other than tree trimming, did you review other aspects of the Company's inspection and maintenance practices?

A. Yes. I looked at the Company's practices involving wood distribution poles, overhead distribution facilities, cross-arms, overhead primary conductors, transformers, and a number of other electric system components. The Company's inspection and maintenance practices seem in line with typical utility practice. There are detailed procedures for inspection practices and for maintenance procedures. Replacement of aging equipment is based on an appraisal of its strength, condition, safety, and impacts on reliability, but not on its numerical age. This is typical of historical electric utility business practices where common distribution system components, such as poles, cross-arms, conductors, distribution transformers, and the like are concerned.

Q. Please comment on the Company's storm restoration practices.

A. The first step in successful electric service restoration after major weather events is to try limit, as much as possible, the number of outages and the amount of damage to begin with. But, effective preparation for and management of the electric service restoration process can help eliminate delays and otherwise facilitate the process.

The Company's performance in the 2011 major storms, and that of the other NJ EDCs, was thoroughly reviewed in the EPP Report. This report made numerous suggestions as to how JCP&L could improve its major storm response and electric service restoration. Since the issuance of the EPP Report, FirstEnergy has issued a new "Emergency Plan for Service Restoration (E-Plan)".[35] This E-Plan was revised on October 26, 2012.

The EPP Report addressed a number of shortcomings in the JCP&L storm restoration process, including, but not limited to: i) the need to plan for bigger storms, or for more than one storm across the FirstEnergy systems at the same time, ii) the need to have an annual exercise for storm operations, iii) the need for FirstEnergy to address how resources are to be allocated across its subsidiaries in the event of multi-area storm damage, and iv) the need to be able to address "wire down" types of situations and initial damage assessment simultaneously.

The new, revised E-Plan appears to address many of these concerns, although it is not clear to what extent that the new E-Plan was able to be implemented and integrated into FirstEnergy's storm operations before Hurricane Sandy hit the JCP&L service territory in late October, 2012. The outage duration metric, CAIDI (with major events), for 2012, which includes Hurricane Sandy, suggests that the amount of electric system damage from Sandy overwhelmed the available resources.

The Board should continue to monitor the implementation of the revised E-Plan when the Company is preparing for major storm conditions and when it is experiencing such conditions to ascertain the extent to which the observations of the EPP Report are

[35] The E-Plan was dated 8-10-12, one day after the date of the EPP Report.

actually being addressed in practice and to verify that lessons learned from Hurricane Sandy are being implemented in the Plan.

Q. Please comment on the Company's priority circuit program.

A. Under N. J. A. C. 14:5-8.7 (g) each EDC reports on its worst 4% distribution circuits based on reliability performance and what corrective actions are planned for these circuits. Currently, JCP&L reports on 22 circuits in its northern area, and 25 circuits in its central area. Prior to about 2008, 10 circuits were reported on from each operating area.

JCP&L's program chooses "worst" circuits from a reliability standpoint based on the reliability metric SAIDI, which reflects the total interruption minutes per customer over a defined period.

Over the past nine years of data for this program, there has been a high rate of repeat distribution circuits in this program. These are summarized in Table 8, below.[36]

Table 8

Number of Circuits That Have Repeated As High Priority Circuits		
	Number of Circuits	
Times Repeated	Northern	Central
2	7	20
3	12	9
4	7	3
5	3	0

[36] Full data is reflected in Exhibit___(PJL-3)

Table 8 shows that i) the same circuits have shown up twice as priority circuits in nine years of data on 7 occasions in the northern area and on 20 occasions in the central area, ii) the same circuits have shown up three times as priority circuits in nine years of data on 12 occasions in the northern area and on 9 occasions in the central area, iii) the same circuits have shown up four times as priority circuits in nine years of data on 7 occasions in the northern area and on 3 occasions in the central area, and iv) the same circuits have shown up 5 times as priority circuits in nine years of data on 3 occasions in the northern area and on zero occasions in the central area. In nine years of data, there were a total of 138 northern area priority circuits reported on, of which 67% reflected circuits repeating more than once. In nine years of data, there were a total of 150 central area priority circuits reported on, of which 53% reflected circuits repeating more than once. By comparison, there are 562 total distribution circuits in the northern area and 630 total distribution circuits in the central area.[37]

My review of the analysis shows that JCP&L has implemented many projects for installing fuses, spacers, lightning arrestors, and animal guards on these worst performing circuits, and, in considerably fewer instances, has implemented projects providing for additional vegetation management, equipment replacements, additional tie points, upgraded conductors, or other reliability replacements. However, more is obviously needed.

It is clear the Company's approach to enhancing reliability on these priority circuits is not working very well. The Company needs to consider the costs and benefits of other

[37] RCR-REL-59 (h).

approaches for improving reliability on these circuits, including more equipment replacements, more aggressive tree trimming, selective use of undergrounding, more advanced circuit protection and sectionalizing, and other potential approaches.

The Board should consider regulations which put more emphasis on improving reliability on these circuits, or which penalizes the Company for failure to improve reliability on its worst performing distribution circuits.

Q. Are there any other reliability metrics that are worth consideration?

A. Yes. While the priority circuit program addresses, to some extent, the interests of customers on poorly performing distribution circuits, it does nothing to address pockets of poor reliability that may exist on the distribution system that are smaller than an entire distribution circuit. While an entire distribution circuit may serve 1,000 or more customers, there are individual taps on these circuits that serve far fewer customers that could have poor reliability and not be noticed by the priority feeder program. As an initial step in considering remedies for the reliability of smaller groups of customers than entire distribution circuits, the Board might wish to consider a metric called “customers experiencing multiple interruptions”, or CEMI.

CEMI is defined by the IEEE as equaling the number of customers experiencing “n” or more sustained interruptions, divided by the total number of customer served. IEEE notes that CEMI is frequently used with n varying from 1 to the highest value of interest.

If such information is reported annually by each EDC, it will provide data on the existence of smaller groups of customers experiencing high numbers of sustained interruptions.

Q. Does this conclude your direct testimony?

A. Yes, at this time.

EXHIBITS TO
PETER J. LANZALOTTA TESTIMONY

Prior Experience Of Peter J. Lanzalotta

Mr. Lanzalotta has more than thirty-five years experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 100 proceedings in 25 states, the District of Columbia, the Provinces of Alberta and Ontario, before the Federal Energy Regulatory Commission, and before U. S. District Court. He has developed evaluations of electric utility system cost, system value, reliability planning, transmission and distribution maintenance practices, and reliability of service.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates in Washington DC for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop’s budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro-Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk’s downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the Association of Energy Engineers, the National Fire Protection Association, and the American Solar Energy Society. He is also registered Professional Engineer in the states of Maryland and Connecticut.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company**, before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board Of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

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24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

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31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

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38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

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45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

46. **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

47. **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

48. **In re: BGE,** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

49. **In re: PEPCO,** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

50. **In re: GenPower Anderson LLC,** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

51. **In re: Pike County Light & Power Company,** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

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52. **In re: Potomac Electric Power Company and Conectiv,** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

53. **In re: South Carolina Electric & Gas Company,** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

54. **In re: Connecticut Light & Power Company,** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

55. **In re: The City of Vernon, California,** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

56. **In re: San Diego Gas & Electric Company et. al.,** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

57. **In re: The City of Vernon, California,** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

58. **In re: Jersey Central Power & Light Company,** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in

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base tariff rates.

59. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

60. **In re: Central Maine Power Company,** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

61. **In re: Metropolitan Edison Company,** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

62. **In re: The California Independent System Operator Corporation,** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

63. **In re: The Narragansett Electric Company,** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

64. **In re: The City of Vernon, California,** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

65. **In re: Atlantic City Electric Company,** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

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66. **In re: Connecticut Light & Power Company and the United Illuminating Company,** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

67. **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

68. **In re: Entergy Louisiana, Inc.,** Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

69. **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

70. **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

71. **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

72. **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey

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Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

73. **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

74. **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

75. **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

76. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

77. **In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

78. **In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

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79. **In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

80. **In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

81. **In re: Application of American Transmission Company to Construct a New Transmission Line,** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

82. **In re: The Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability,** Case No. 06-222-EL-SLF, on behalf of The Office of The Ohio Consumers' Counsel, before the Public Utilities Commission of Ohio, concerning distribution system reliability and related topics.

83. **In re: Central Maine Power Company,** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

84. **In re: Bangor Hydro Electric Company,** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

85. **In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,** Docket No. 33672, on behalf of the Texas Office

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of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

86. **In re: Virginia Electric and Power Company,** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

87. **In re: Trans-Allegheny Interstate Line Company,** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

88. **In re: Commonwealth Edison Company,** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

89. **In re: Commonwealth Edison Company,** Docket No. 07-0491, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning the applicability of electric service interruption provisions.

90. **In re: Hydro One Networks ,** Case No. EB-2007-0050, on behalf of Pollution Probe, before the Ontario Energy Board, concerning a request for leave to construct electric transmission facilities in the Province of Ontario.

91. **In re: PEPCO Holdings, Inc.,** Docket No. ER-08-686-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

92. **In re: PPL Electric Utilities Corporation and Public Service Electric and Gas Company,** Docket No. ER-08-23-000, on behalf of the Joint Consumer Advocates, including the state consumer advocacy offices for the States of

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Maryland, West Virginia, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

93. **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2008-2022941 and P-2008-2038262, on behalf of Springfield Township, Bucks County, PA, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and a proposed electric substation.

94. **In re: PEPCO Holdings, Inc.,** Docket No. ER08-1423-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

95. **In re: Public Service Electric and Gas Company, Inc.,** Docket No. ER09-249-000, on behalf of the New Jersey Division of Rate Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

96. **In re: New York Regional Interconnect Inc.,** Case No. 06-T-0650, on behalf of the Citizens Against Regional Interconnect, before the New York Public Service Commission, concerning the economics of and alternatives to proposed transmission facilities.

97. **In re: Central Maine Power Company and Public Service of New Hampshire,** Docket No. 2008-255, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning CMP's and PSNH's Petition for Finding of Public Convenience & Necessity to build the Maine Power Reliability Project, a series of new and rebuilt electric transmission facilities to operate at 345 kV and 115 kV in Maine and New Hampshire.

98. **In re: PPL Electric Utilities Corporation, Docket No. A-2009-2082652 et al,** on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the Company's application for approval to site and construct electric transmission facilities in Pennsylvania.

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99. **In re: Bangor Hydro-Electric,** Docket No. 2009-26, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning BHE's Petition for Certificate of Public Convenience & Necessity to build a 115 kV transmission line in Washington and Hancock Counties.

100. **In re: United States, et al. v. Cinergy Corp., et al.** Civil Action No. IP99-1693 C-M/S, on behalf of Plaintiff United States and Plaintiff-Intervenors State of New York, State of New Jersey, State of Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, before the United States District Court for the Southern District of Indiana, concerning the system reliability impacts of the potential retirement of Gallagher Power Station Unit 1 and Unit 3.

101. **In re: Application of Potomac Electric Power Company, et al.** Case No. 9179, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the application for a determination of need under a certificate of public convenience and necessity for the Maryland portion of the MAPP transmission line, and related facilities.

102. **In re: Potomac Electric Power Company v. Perini/Tompkins Joint Venture,** Case No. 9210, on behalf of Perini Tompkins before the Maryland Public Service Commission concerning a review of PEPCO's estimates of electric consumption by Perini Tompkins Joint Venture's temporary electric service at National Harbor during a 29 month period for which no metered consumption data is available.

103. **In re: Duke Energy Ohio, Inc.,** Case No. 10-503-EL-FOR, on behalf of the Natural Resources Defense Council and Sierra Club before the Public Utilities Commission Of Ohio, concerning a review of the reliability impacts that would result from closure of selected generating units as part of a review of Duke's 2010 Electric Long-Term Forecast Report and Resources Plan.

104. **In re: Detroit Edison Company,** Case Nos. U-16472 and 16489, on behalf of the Michigan Environmental Council and the Natural Resources Defense Council, before the Michigan Public Service Commission, concerning a review looking for studies of the reliability impacts that would result from closure of selected generating units as part of an electric rate increase case.

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105. **In re: Potomac Electric Power Company,** Case No. 9240, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability performance.

106. **In re: ISO New England, Inc.,** Docket No. ER12-991-000, on behalf of the Conservation Law Foundation, before the Federal Energy Regulatory Commission, concerning proposals for procedures for obtaining temporary regulations addressing emissions from electric generating facilities.

107. **In re: Western Massachusetts Electric Company, Docket No. D.P.U. 11-119-C** on behalf of the Attorney General of the Commonwealth of Massachusetts, before the Massachusetts Department of Public Utilities, concerning storm preparation, performance, and restoration of electric service.

108. **In re: Delmarva Power & Light Company,** Case No. 9285, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

109. **In re: Potomac Electric Power Company,** Case No. 9286, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

110. **In re: Duke Energy Indiana, Inc.,** Cause No. 44217, on behalf of Citizens Action Coalition of Indiana, Sierra Club, Save The Valley, and Valley Watch, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

111. **In re: Indianapolis Power & Light Company,** Cause No. 44242, on behalf of Citizens Action Coalition of Indiana and the Sierra Club, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

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112. **In re: Consumers Energy Company,** Case No. U-17087, on behalf of Michigan Environmental Council and Natural Resources Defense Council, before the Michigan Public Service Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

113. **In re: Potomac Electric Power Company,** Case No. 9311, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters and tree trimming expenses as part of a base rate increase case.

	A	B	C	D	E	F
1						
2	Number of Circuits That Have Repeated As High Priority Circuits					
3			Number of Circuits			
4		Times Repeated	Northern	Central		
5		2	7	20		
6		3	12	9		
7		4	7	3		
8		5	3	0		
9						
10		Repeat Slots		Percent of total		
11		North	Central	North	Central	
12		14	40	10.14%	26.67%	
13		36	27	26.09%	18.00%	
14		28	12	20.29%	8.00%	
15		15	0	10.87%	0.00%	
16						
17		93	79	67.39%	52.67%	
18						
19						
20		Total Slots	North	Central		
21		2003	10	10		
22		2004	10	10		
23		2005	10	10		
24		2006	10	10		
25		2007	10	10		
26		2008	22	25		
27		2009	22	25		
28		2010	22	25		
29		2011	22	25		
30		total	138	150		
31						
32						
33						
34		Roster Sorted By Circuit Number				
35		Circuit	Year	Area		
36		17014	2005/2006	Northern		
37		17302	2005/2006	Northern		
38		17302	2009/2010	Northern		
39		17302	2010/2011	Northern		
40		17530	2010/2011	Northern		
41		17535	2003/2004	Northern		
42		17541	2011/2012	Northern		
43		17543	2009/2010	Northern		
44		17544	2007/2008	Northern		
45		17544	2010/2011	Northern		
46		17547	2002/2003	Northern		
47		17548	2002/2003	Northern		
48		17557	2004/2005	Northern		
49		17566	2007/2008	Northern		
50		17566	2010/2011	Northern		
51		17566	2011/2012	Northern		
52		17577	2007/2008	Northern		
53		17577	2010/2011	Northern		
54		17605	2002/2003	Northern		
55		17605	2007/2008	Northern		
56		17605	2009/2010	Northern		
57		17605	2011/2012	Northern		
58		17627	2010/2011	Northern		
59		17630	2002/2003	Northern		
60		17630	2003/2004	Northern		
61		17630	2006/2007	Northern		
62		17630	2007/2008	Northern		
63		17630	2010/2011	Northern		
64		17632	2010/2011	Northern		
65		17645	2009/2010	Northern		
66		17647	2006/2007	Northern		
67		17649	2009/2010	Northern		
68		17650	2011/2012	Northern		
69		17655	2004/2005	Northern		
70		17655	2005/2006	Northern		
71		17655	2007/2008	Northern		
72		17655	2010/2011	Northern		
73		17655	2011/2012	Northern		
74		17656	2004/2005	Northern		
75		17656	2005/2006	Northern		
76		17656	2007/2008	Northern		
77		17656	2009/2010	Northern		
78		17656	2010/2011	Northern		
79		17696	2004/2005	Northern		
80		17696	2005/2006	Northern		
81		17696	2009/2010	Northern		

	A	B	C	D	E	F
82		17696	2010/2011	Northern		
83		17700	2011/2012	Northern		
84		17729	2003/2004	Northern		
85		17729	2009/2010	Northern		
86		17730	2004/2005	Northern		
87		17735	2009/2010	Northern		
88		17735	2011/2012	Northern		
89		17736	2004/2005	Northern		
90		17736	2005/2006	Northern		
91		17736	2009/2010	Northern		
92		17736	2010/2011	Northern		
93		17737	2006/2007	Northern		
94		17737	2009/2010	Northern		
95		17737	2011/2012	Northern		
96		17740	2004/2005	Northern		
97		17740	2009/2010	Northern		
98		17740	2010/2011	Northern		
99		17740	2011/2012	Northern		
100		17743	2011/2012	Northern		
101		17751	2002/2003	Northern		
102		17751	2007/2008	Northern		
103		17751	2009/2010	Northern		
104		17777	2007/2008	Northern		
105		17777	2009/2010	Northern		
106		17777	2010/2011	Northern		
107		17785	2002/2003	Northern		
108		17785	2005/2006	Northern		
109		17785	2006/2007	Northern		
110		17785	2010/2011	Northern		
111		17802	2003/2004	Northern		
112		17802	2009/2010	Northern		
113		17802	2010/2011	Northern		
114		17804	2004/2005	Northern		
115		24653	2011/2012	Northern		
116		27034	2007/2008	Northern		
117		27052	2007/2008	Northern		
118		27052	2011/2012	Northern		
119		27410	2002/2003	Northern		
120		27410	2007/2008	Northern		
121		27410	2009/2010	Northern		
122		27453	2011/2012	Northern		
123		27528	2002/2003	Northern		
124		27534	2007/2008	Northern		
125		27534	2010/2011	Northern		
126		27535	2003/2004	Northern		
127		27535	2006/2007	Northern		
128		27535	2010/2011	Northern		
129		27591	2009/2010	Northern		
130		27592	2006/2007	Northern		
131		27592	2007/2008	Northern		
132		27592	2010/2011	Northern		
133		27593	2010/2011	Northern		
134		27615	2007/2008	Northern		
135		27635	2007/2008	Northern		
136		27666	2007/2008	Northern		
137		27666	2009/2010	Northern		
138		27666	2009/2010	Northern		
139		27683	2002/2003	Northern		
140		27683	2004/2005	Northern		
141		27683	2006/2007	Northern		
142		27683	2007/2008	Northern		
143	xxxxxxxxxx	27706	2009/2010	Northern		
144		27714	2007/2008	Northern		
145		27720	2009/2010	Northern		
146		27731	2005/2006	Northern		
147		27731	2006/2007	Northern		
148		27731	2007/2008	Northern		
149		27732	2011/2012	Northern		
150		33827	2011/2012	Northern		
151		33970	2003/2004	Northern		
152		33984	2003/2004	Northern		
153		37676	2011/2012	Northern		
154		37755	2006/2007	Northern		
155		37756	2003/2004	Northern		
156		37789	2005/2006	Northern		
157		37792	2005/2006	Northern		
158		37794	2010/2011	Northern		
159		37811	2011/2012	Northern		
160		37823	2004/2005	Northern		
161		37823	2006/2007	Northern		
162		37823	2009/2010	Northern		

	A	B	C	D	E	F
163		37823	2010/2011	Northern		
164		37825	2007/2008	Northern		
165		37825	2011/2012	Northern		
166		37855	2003/2004	Northern		
167		37855	2007/2008	Northern		
168		37855	2011/2012	Northern		
169		37876	2002/2003	Northern		
170		37890	2011/2012	Northern		
171		37940	2003/2004	Northern		
172		37972	2011/2012	Northern		
173		37989	2011/2012	Northern		
174		47050	2007/2008	Central		
175		47050	2011/2012	Central		
176		47076	2009/2010	Central		
177		47084	2007/2008	Central		
178		47085	2003/2004	Central		
179		47086	2009/2010	Central		
180		47087	2005/2006	Central		
181		47087	2009/2010	Central		
182		47087	2010/2011	Central		
183		47087	2011/2012	Central		
184		47090	2007/2008	Central		
185		47090	2009/2010	Central		
186		47102	2005/2006	Central		
187		47102	2007/2008	Central		
188		47104	2009/2010	Central		
189		47104	2010/2011	Central		
190		47156	2009/2010	Central		
191		47171	2011/2012	Central		
192		47172	2009/2010	Central		
193		47181	2003/2004	Central		
194		47181	2010/2011	Central		
195		47181	2011/2012	Central		
196		47194	2004/2005	Central		
197		47194	2010/2011	Central		
198		47196	2002/2003	Central		
199		47285	2011/2012	Central		
200		47306	2004/2005	Central		
201		47325	2006/2007	Central		
202		47327	2002/2003	Central		
203		47329	2007/2008	Central		
204		47330	2004/2005	Central		
205		47331	2009/2010	Central		
206		47331	2010/2011	Central		
207		47331	2011/2012	Central		
208		47332	2010/2011	Central		
209		47357	2006/2007	Central		
210		47383	2011/2012	Central		
211		47384	2002/2003	Central		
212		47384	2004/2005	Central		
213		47396	2005/2006	Central		
214		47399	2010/2011	Central		
215		47406	2003/2004	Central		
216		47418	2007/2008	Central		
217		47427	2009/2010	Central		
218		47427	2010/2011	Central		
219		47428	2009/2010	Central		
220		47491	2011/2012	Central		
221		47702	2005/2006	Central		
222		47716	2007/2008	Central		
223		47880	2006/2007	Central		
224		53183	2011/2012	Central		
225		53213	2009/2010	Central		
226		53229	2006/2007	Central		
227		57036	2009/2010	Central		
228		57068	2003/2004	Central		
229		57070	2007/2008	Central		
230		57070	2009/2010	Central		
231		57168	2009/2010	Central		
232		57335	2010/2011	Central		
233		57337	2010/2011	Central		
234		57343	2009/2010	Central		
235		57352	2005/2006	Central		
236		57352	2009/2010	Central		
237		57352	2011/2012	Central		
238		57363	2002/2003	Central		
239		57382	2005/2006	Central		
240		57385	2007/2008	Central		
241		57385	2011/2012	Central		
242		57442	2002/2003	Central		
243		57456	2002/2003	Central		

	A	B	C	D	E	F
244		57460	2002/2003	Central		
245		57460	2010/2011	Central		
246		57478	2009/2010	Central		
247		57737	2010/2011	Central		
248		57738	2006/2007	Central		
249		57739	2006/2007	Central		
250		57739	2007/2008	Central		
251		57739	2010/2011	Central		
252		64035	2010/2011	Central		
253		67004	2007/2008	Central		
254		67005	2003/2004	Central		
255		67047	2003/2004	Central		
256		67047	2010/2011	Central		
257		67052	2003/2004	Central		
258		67052	2009/2010	Central		
259		67210	2007/2008	Central		
260		67262	2002/2003	Central		
261		67285	2009/2010	Central		
262		67291	2007/2008	Central		
263		67291	2011/2012	Central		
264		67292	2004/2005	Central		
265		67294	2004/2005	Central		
266		67295	2011/2012	Central		
267		67303	2009/2010	Central		
268		67306	2009/2010	Central		
269		67309	2011/2012	Central		
270		67310	2005/2006	Central		
271		67312	2005/2006	Central		
272		67312	2007/2008	Central		
273		67312	2010/2011	Central		
274		67313	2007/2008	Central		
275		67313	2011/2012	Central		
276		67314	2011/2012	Central		
277		67319	2011/2012	Central		
278		67345	2007/2008	Central		
279		67345	2011/2012	Central		
280		67347	2002/2003	Central		
281		67354	2010/2011	Central		
282		67355	2010/2011	Central		
283		67356	2003/2004	Central		
284		67398	2003/2004	Central		
285		67412	2010/2011	Central		
286		67455	2010/2011	Central		
287		67456	2003/2004	Central		
288		67494	2007/2008	Central		
289		67495	2005/2006	Central		
290		67501	2010/2011	Central		
291		67503	2004/2005	Central		
292		67503	2007/2008	Central		
293		67527	2004/2005	Central		
294		67533	2006/2007	Central		
295		67533	2009/2010	Central		
296		67533	2011/2012	Central		
297		69287	2007/2008	Central		
298		69287	2009/2010	Central		
299		69288	2004/2005	Central		
300		69288	2005/2006	Central		
301		69288	2007/2008	Central		
302		69288	2009/2010	Central		
303		69328	2002/2003	Central		
304		69328	2007/2008	Central		
305		69329	2009/2010	Central		
306		69329	2011/2012	Central		
307		69361	2010/2011	Central		
308		69504	2007/2008	Central		
309		69504	2010/2011	Central		
310		69504	2011/2012	Central		
311		69505	2004/2005	Central		
312		69505	2006/2007	Central		
313		69505	2007/2008	Central		
314		69506	2006/2007	Central		
315		69506	2007/2008	Central		
316		69506	2010/2011	Central		
317		69506	2011/2012	Central		
318		69507	2010/2011	Central		
319		69507	2011/2012	Central		
320		69509	2006/2007	Central		
321		69509	2007/2008	Central		
322		69509	2011/2012	Central		
323		69510	2011/2012	Central		
324						

REFERENCE MATERIALS TO
PETER J. LANZALOTTA TESTIMONY

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases In and Other Adjustments to its Rates and Charges for Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-2 Referencing the Direct Testimony of Ralph C. Hillmer, on page 6 lines 6-8 it states the number of miles of distribution circuits and sub-transmission circuits that are maintained by the Company as part of its Distribution Vegetation Management Program:

a. Please identify the primary voltages at which the Company's distribution circuits operate.
b. Please state the total circuit miles for each of the primary voltages at which the Company's distribution circuits operate.
c. Please state the total overhead circuit miles for each of the primary voltages at which the Company's distribution circuits operate.
d. Please state the total overhead three-phase circuit miles for each of the primary voltages at which the Company's distribution circuits operate.
e. Please state the total overhead three-phase circuit miles for each of the primary voltages at which the Company's distribution circuits operate which share a pole line with another distribution circuit.
f. Please state the total overhead three-phase circuit miles for each of the primary voltages at which the Company's distribution circuits operate which share a pole line with a sub-transmission circuit.
g. Please identify the primary voltages at which the sub-transmission feeders operate.
h. Please state the total circuit miles for each of the primary voltages at which the Company's sub-transmission circuits operate.
i. Please state the total overhead circuit miles for each of the primary voltages at which the Company's sub-transmission circuits operate.
j. Please state the total overhead circuit miles for each of the primary voltages at which the Company's sub-transmission circuits operate which share a pole line with a distribution circuit.
k. Please state the total overhead circuit miles for each of the primary voltages at which the Company's sub-transmission circuits operate which share a pole line with another sub-transmission circuit.

Response:

a. JCP&L's distribution circuits operate at 19.9 kV (Wye), 12.5 kV (Wye), 4.8 kV (Delta) and 4.16 kV (Wye). The wye-configured portion of the sub-transmission system that is operated at 19.9 kV is included in distribution rates and in response to this question.

b. See the table below.

Voltage	Total Circuit Miles	Overhead Circuit Miles	Three Phase Overhead Circuit Miles
19.9 kV	597.7	270.4	315.6
12.5 kV	15,174.2	9,021.3	4,095.6
4.8 kV	2,010.7	1,648.8	1,176.5
4.16 kV	1,305.9	1,072.2	554.7
Total	**19,088.5**	**12,012.6**	**6,142.3**

Note: *The 12,012 miles of circuits set forth in the table above represents an improved estimate as compared to the 12,566 miles of distribution circuits reported in Mr. Hillmer's testimony (Exhibit JC-16 at 6:6).*

c. See the response to part b.

d. See the response to part b.

e. The Company does not track circuit mileage in the manner requested and the information requested is not available. In addition, the manner in which data regarding electrical facility structures is contained in GIS does not, as a practical matter, accommodate the type of analysis that might produce such information.

f. See the response to part e.

g. The primary voltages at which most sub-transmission circuits operate is 34.5 kV. However, the Wye-configured portion of the sub-transmission system is operated at a primary voltage of 19.9 kV and that part of the sub-transmission system is included in distribution rates.

h. Total circuit miles for 34.5 kV sub-transmission circuits is 1,802 miles.

i. Total overhead circuit miles for 34.5 kV sub-transmission circuits is 1,625 miles.

Note: *The 1,625 miles of circuits reported here represents an improved estimate as compared to the 1,736 miles of sub-transmission circuits reported in Mr. Hillmer's testimony (Exhibit JC-16 at 6:7).*

j. See the response to part e.

k. See the response to part e.

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BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-5 Revised For each of the years 2002 through 2012, please state the:

a. total tree trimming budget for the Company's distribution system circuits;
b. actual total expenditures incurred by the Company to inspect for vegetation management purposes and, if necessary, trim its distribution system circuits;
c. total number of miles of its distribution system circuits the Company planned or targeted for inspection, for vegetation management purposes, and, if necessary, trimming;
d. total number of miles of its distribution system circuits actually inspected for vegetation management purposes by the Company; and
e. total number of miles of its distribution system circuits actually trimmed by the Company.

Response: The Company objects to this request insofar as it seeks data for periods of time that are outside the scope of this proceeding. Without waiving this objection, as a courtesy, the Company responds as follows:

Please note that the requested types of mileage information was not tracked electronically in IVMS until 2005 and therefore the responses to parts c, d, and e are provided for years 2005 to 2012.

a. Please ***see*** RCR-REL-005 Attachment 1, which provides the total capital and O&M budget and actual expenditure data for the distribution vegetation management program for the years 2002-2012. Please note that these amounts do not include (i) project-related, (ii) unplanned, and (iii) storm-related vegetation management expenditures for any given year.
b. ***See*** the response to part a.
c. Please ***see*** RCR-REL-005 Attachment 2, which provides the total miles "targeted" for distribution vegetation management in 2005-2012. Please read the note related to this attachment for further context. Please ***see also*** Mr. Hillmer's testimony regarding the corridor-widening program undertaken in the 2009-2012 time frame.
d. ***See*** the response to part c.
e. ***See*** the response to part c.

*****REVISION*****

The ***original*** RCR-REL-005 **Attachment 2**, which shows the total miles planned. total miles inspected and total miles trimmed, was mislabeled RCR-REL-005 **Attachment 1**. ***See*** the replacement RCR-REL-005 Attachment 2, which is now correctly labeled.

Distribution

Year	Total Miles Planned (c)	Total Miles Inspected (d)	Total Miles Trimmed (e)[1]
2005	3073	3073	3073
2006	1784	1784	1784
2007	2842	2842	2842
2008	3923	3923	3923
2009	3382	3382	3382
2010	2945	2945	2945
2011	2925	2925	2925
2012	4001	4001	4001

Note

[1]The above chart merely shows that the" planned" or" targeted" vegetation miles and that they were eventually were inspected and trimmed (as necessary) but without detailed specification as to when these actions were actually completed. Please note that IVMS tracks circuit mileage, as well as the date work is started and finished. However, the dates are only available beginning for years 2008 and forward and "finished" means not only that the trimming was completed, but also means that the quality control ("QC") related to the trimming was also performed and the results of the QC indicate that the trimming was done satisfactorily. This background information is necessary to understand that those instances in 2009, 2010 and 2011 when tree trimming (as opposed to inspection) was not completed by the end of the cycle year, as mentioned in Mr. Hillmer's testimony, do not appear in IVMS. As the Company reported in its 2010 and 2011 ASPR certain limited amounts of trimming was deferred for completion in a subsequent cycle year, mostly completed by December 31, 2011 with a small amount of remaining work deferred into 2012 due to the impact of Hurricane Irene and the October 2011 snowstorm. These deferrals were tracked manually by the JCP&L Vegetation Management department.

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BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-59 For each of i) Hurricane Irene, ii) the October 2011 snow storm, and iii) Hurricane Sandy (each individually "the Storm"), please provide:

a. A copy of the Company's procedures and practices for determining service restoration priorities which were in effect for each Storm;
b. A list of the types of governmental facilities that typically get service restoration priority;
c. An estimate of the total number of governmental facilities that typically get service restoration priority that are located in each of the Company's Northern and Central service areas;
d. A list of the types of commercial facilities that typically get service restoration priority;
e. An estimate of the total number of commercial facilities that typically get service restoration priority that are located in each of the Company's Northern and Central service areas;
f. A list of the types of residential service customers that typically get service restoration priority;
g. An estimate of the total number of residential service customers that typically get service restoration priority that are located in each of the Company's Northern and Central service areas;
h. The number of distribution feeders that are located in each of the Company's Northern and Central service areas.
i. An estimate of the percentage of the distribution feeders that are located in each of the Company's Northern and Central service areas that served at least one customer with electric service restoration priority.

Response: JCP&L generally objects to data requests regarding Hurricane Irene, the October 2011 Snow storm and Hurricane Sandy (and the subsequent Nor'easter), which cover the same ground that was or is being addressed in Board proceedings (i.e., BPU Docket No. EO11090543 and EO12111050) specifically related to such events. Please also note that on January 23, 2013, the Board issued an order with respect to its, and the Board Staff's, review of the EPP Report in BPU Docket No. EO11090543 and initiatives, to address the development and implementation of approaches, programs, processes, projects, responses and strategies, which comply with the Staff recommendations adopted by the Board in its January 23, 2013 order, are underway. Nevertheless, subject to, and without waiving, the objection, and as a courtesy, JCP&L provides the following response:

a. Service Restoration Priorities – Procedures
   i) Hurricane Irene – ***See*** RCR-REL-17 Attachment 2 page 25 for the sequence of emergency activities.
   ii) October 2011 Snow storm - ***See*** RCR-REL-17 Attachment 2 page 25 for the sequence of emergency activities.
   iii) Hurricane Sandy - ***See*** RCR-CS-92 Attachment 1 pages 30-31 for the sequence of emergency activities.

b., d., and f.

In general, the process of restoring service to customers is designed to restore power to the greatest number of customers in the shortest period of time as well as to provide priority restoration to distribution customers that provide functions essential to the health and safety of the communities we serve. As shown in RCR-CS-92 Attachment 1 (on pages 30-31), the distribution restoration priorities occur in no particular order but are incident specific. Prudent business judgments taking into account the prevailing conditions at the time may dictate variations in the service restoration priorities from storm event to storm event. These priorities include a variety of governmental facilities and commercial facilities as well as certain residential service customers, of the following types (the order of which here below merely follows the order set forth in the data request), which may, will and do vary depending on the unique circumstances of each particular outage event:

TYPES OF FACILITIES AND CUSTOMERS ELIGIBLE
FOR
RESTORATION PRIORITIZATION

Governmental Facilities
– State and County Offices of Emergency Management
– Countywide 9-1-1 System (Centers and towers)
– Military Installations
– Airport control towers
– City, village, township halls
– Water supply and pumping stations
– Sewage treatment system
– Police departments
– Fire departments
– Correctional institutions

Commercial Facilities

– Hospitals
– Large nursing homes with critical life support customers
– Emergency Shelters
– Rural Electric Cooperatives (REC's)/Rural Electric Associations (REA's)
– Natural Gas Company
– Telephone exchanges
– Radio and Television stations and Newspapers
– Schools

Residential Customers

– Critical life support customers[1]
– Well-water customers
(in both cases, once restoration is to the single customer level).

In times of significant outage events, the Company coordinates the identification of critical facilities with the county OEMs and complies with Board directives, which require the identification of critical facilities.

c., e., and g.

As stated above, and in other data request responses (*see* footnote 1), in times of significant outage events, the Company coordinates the identification of critical facilities with the county OEMs regarding restoration priorities. As indicated elsewhere, individual critical care customers can, as a practical operations matter, only be given priority relative to restoration when overall restoration efforts have reached the point at which service is being to individual homes.

[1] Critical Care customers are defined as those using electrically operated life support equipment. New Jersey regulation (N.J.A.C. 14:3-3A.4 (d)), requires that the electric and gas utilities solicit information on a semi-annual basis to determine the presence of said equipment. Customers must voluntarily enroll for this service and are advised, via bill insert, that the list will be provided to County and Municipal OEMs. As explained in RCR-CS-98, Critical care customers receive outbound calls from the Company IVR system 48 and 24 hours prior to a forecasted storm. In addition, critical care customers can obtain information concerning their outage from the Company by calling the 888-LIGHTSS and obtaining information from the IVR, or by selecting to speak to a customer service representative, who can communicate the estimated restoration time. The Company uses critical care customers as a factor in determining restoration efforts. However, it is one factor out of many factors used to determine where restoration efforts should be dedicated first. Priority is given to hospitals, critical care and life support facilities, communications facilities, emergency response agencies and circuits serving the largest number of customers, followed by restoration of service to individual homes, which is when individual critical care customers can, as a practical operations matter, be given priority relative to restoration.

However, relative to each of the storms as to which this request is directed, and, generally, the Company does not have an available estimate, or compile the data in a format to readily produce an estimate, of the "total number" of governmental facilities, commercial facilities and residential service customers "that typically get service restoration priority that are located in each of the Company's Northern and Central service areas."

h. Number of distribution feeders
Central New Jersey has a total of 630 distribution feeders and Northern New Jersey has a total of 562 distribution feeders.

i. Percentage of distribution feeders
In Central New Jersey, it is estimated that approximately 70% of the distribution feeders serve at least one type of facility or customer eligible (depending on the facts and circumstances of the presenting outage event) for distribution outage restoration priority as defined in the E-Plan (please *__see__* RCR-REL-92).

In Northern New Jersey, it is estimated that approximately 65% of the distribution feeders serve at least one type of facility or customer eligible (depending on the facts and circumstances of the presenting outage event) for distribution outage restoration priority as defined in the E-Plan (please *__see__* RCR-REL-92).

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BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-74 Referencing the Direct Testimony of Ralph C. Hillmer, on page 10 lines 10-18, it addresses a corridor widening initiative for distribution circuits. Regarding this initiative:

a. Please describe the desired side clearance (in terms of feet or years growth) that is sought for each primary distribution voltage. If this varies depending on location on the circuit (backbone, lateral, etc.), or depending on the number of primary phases, please describe how.
b. Please describe the desired treatment of tree limbs located over primary distribution voltage conductors that is sought for each primary distribution voltage. If this varies depending on location on the circuit (backbone, lateral, etc.), or depending on the number of primary phases, please describe how.
c. Please describe the desired treatment of tree limbs located over cleared right of way (other than immediately over the conductors) that is sought for each primary distribution voltage. If this varies depending on location on the circuit (backbone, lateral, etc.), or depending on the number of primary phases, please describe how.
d. Please describe whether corridor widening is performed as part of the normal trimming cycle or on some other basis.
e. For each of the years from 2009 to the present, please describe i) which distribution circuits have undergone corridor widening, ii) how many circuit miles on each circuit have undergone the corridor widening initiative, and iii) the primary voltage of each circuit.
f. For each of the years from 2009 to the present, please describe the cost of this corridor widening initiative.
g. Please provide a copy of any estimate prepared by or for the Company i) of the reliability improvement expected as a result of the corridor widening initiative and/or ii) of the cost of the initiative.
h. Please describe to what extent the effects of this corridor widening initiative have manifested themselves in terms of improved reliability performance, on the circuits that have undergone corridor widening, during Hurricane Irene, the October 2011 snow storm, and/or Hurricane Sandy.

Response:

a. As Mr. Hillmer explains in his testimony, the corridor widening initiative attempted to widen the traditional trimming corridors for the Company's distribution circuits where practical and to remove overhang on selected circuits in order to create additional clearance space between trees, limbs and overhang beyond the typical 15 feet of clearance from all sides of the conductor (including to a height of 15 feet above the conductor), (although, as Mr. Hillmer mentioned, this can vary depending on tree species and growth rate. Beyond this goal and because corridor widening involves situations outside of the Company's existing rights-of-way, there was no predefined "desired side clearance." Please ***see*** the Company's response to RCR-REL-9 and RCR-REL-10. With the corridor widening initiative the Company is removing healthy overhanging limbs.

b. ***See*** the response to part a.

c. ***See*** response to part a.

d. Corridor widening is conducted concurrently with the scheduled vegetation management maintenance cycle.

e. Please ***see*** RCR-REL-74 Attachment 1 for the 2009 circuits and miles that have undergone corridor widening as part of the 2009-2012 corridor widening initiative described in Mr. Hillmer's testimony.

   Please ***see*** RCR-REL-74 Attachment 2 for the 2010 circuits and miles that have undergone corridor widening as part of the 2009-2012 corridor widening initiative described in Mr. Hillmer's testimony.

   Please ***see*** RCR-REL-74 Attachment 3 for the 2011 circuits and miles that have undergone corridor widening as part of the 2009-2012 corridor widening initiative described in Mr. Hillmer's testimony.

   Please ***see*** RCR-REL-74 Attachment 4 for the 2012 circuits and miles that have undergone corridor widening as part of the 2009-2012 corridor widening initiative described in Mr. Hillmer's testimony.

   Please note that all of the circuits that were part of the 2009-2012 corridor widening initiative described in Mr. Hillmer's testimony were distribution voltage circuits.

f. The total cost of the distribution Vegetation Management Program for 2009 - 2012 is provided in response to Bur-Eng-49. During this period, there was an increase in capitalization and costs due to the corridor widening initiative. A detailed breakdown of the incremental cost of the special corridor widening initiative described by Mr. Hillmer in his testimony would be difficult to determine, since there was a shift from O&M to capital as increased trimming costs related to more vegetation being removed were incurred. This is evident in the increased program costs from year to year.

g. Mr. Hillmer discusses some specific preliminary reliability impacts on pages 12-13 of his testimony. As an overview, the Company anticipates that the corridor widening initiative will have a significant impact on SAIFI as well as result in an improvement to the Company's overall CAIDI performance. There were no specific estimates prepared regarding either the extent of anticipated reliability improvement or the cost of the initiative. As Mr. Hillmer also discusses in his testimony regarding preventable and non-preventable tree outages, given the reduction in preventable tree-caused outages, the Company thought there was a logical opportunity for improvement in non-preventable tree-cause outages through the corridor widening initiative. This focus is in response to a desire to improve reliability as well as to minimize physical damage to electrical distribution facilities from tree-caused outages. These non-preventable tree-related outages were attributed to overhanging branches above and adjacent to conductors and dead or defective trees falling from outside the distribution corridor. Portions of a circuit that experience higher customer interruption minutes due to these vegetation-caused outages were targeted to receive a visual inspection and tree trimming which includes, if necessary, the removal of certain healthy limbs, which overhang primary conductors. Additionally, off-corridor trees that are dying or significantly declining were targeted for potential removal (assuming consent from the property owners).

h. The Company objects to data requests regarding Hurricane Irene, the October 2011 Snow storm and Hurricane Sandy (and the subsequent Nor'easter), which cover the same ground that was or is being addressed in Board proceedings (i.e.. BPU Docket No. EO11090543 and EO12111050) specifically related to such events. Furthermore, please also note that on January 23, 2013, the Board issued an order with respect to its, and the Board Staff's, review of the EPP Report in BPU Docket No. EO11090543, which also addresses similar issues and provides numerous recommendations regarding similar matters, which the Company is currently in the process of addressing in accordance with the Board's order. Nevertheless, subject to, and without waiving, the objection, and as a courtesy, JCP&L provides the following response:"

   Circuits that received corridor widening work did benefit from these efforts during Hurricane Irene and the October 2011 snowstorm. Approximately, fifteen percent of the JCP&L circuit miles had corridor widening applied to some portion. During Hurricane Irene 87% of the outages to customers occurred on the 85% of non-widened circuit miles. During the October 2011 snowstorm 89% of the outages to customers occurred on the 85% of non-widened circuit miles. However, due to the catastrophic nature of Hurricane Sandy it cannot be claimed that the corridor widening initiative had a benefit to reliability performance during that event.

   With the conclusion in 2012 of a complete 4-year cycle of corridor widening, the Company is continuing to review and evaluate the reliability benefits resulting from the corridor-widening program.

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2009	TAYLORTOWN SUB	37720	10.92	Dist
2009	GRANDIN SUB	27706	15.57	Dist
2009	BROADWAY27635(80157 0145)	27635	16.02	Dist
2009	FURNACE BROOK SUB	27534	23.6	Dist
2009	KITTATINNY SUB	17577	18.82	Dist
2009	FURNACE BROOK SUB	27535	20.35	Dist
2009	BROADWAY27634(80157 0144)	27634	12.04	Dist
2009	FRANKLIN14538(80186 0348)	14538	5.11	Dist
2009	PERRYVILLE27034(80239 0803)	27034	8.27	Dist
2009	STONE CHURCH - 57352	57352	9.24	Dist
2009	JACKSONVILLE33828(80205 0477)	33828	3.03	Dist
2009	FRENEAU - 47328	47328	5.82	Dist
2009	JACKSONVILLE33826(80205 0475)	33826	3.67	Dist
2009	FRENEAU - 47331	47331	4.7	Dist
2009	TAYLORTOWN SUB	37721	10.39	Dist
2009	OKNER37870(80232 0767)	37870	4.75	Dist
2009	STONE CHURCH - 57351	57351	7.68	Dist
2009	WAVERLY37990(80270 1065)	37990	1.57	Dist
2009	KEANSBURG - 47157	47157	4.27	Dist
2009	GILLETTE37940(80191 0374)	37940	10.73	Dist
2009	FAIRHAVEN SUBSTATION	54208	4.67	Dist
2009	WHITNEY37736(80274 1095)	37736	9.3	Dist
2009	KENVIL17626(80206 0495)	17626	9.09	Dist
2009	CLINTON27673(80166 0197)	27673	9.59	Dist
2009	HIGHLAND - 53145	53145	1.99	Dist
2009	GREEN GROVE SUBST	57448	7.86	Dist
2009	ISLAND HEIGHTS SUB	67455	8.78	Dist
2009	WEST PORTAL24567(80272 1081)	24567	8.47	Dist
2009	NORTH BRANCH27615(80231 0758)	27615	10.59	Dist
2009	STONEYBROOK37653(80258 0966)	37653	5.38	Dist
2009	PARSIPPANY SUB	37676	7.64	Dist
2009	KENVIL17627(80206 0496)	17627	10.09	Dist
2009	MIDDLETOWN - 57461	57461	4.96	Dist
2009	WOODLAND - 57070	57070	6.28	Dist
2009	FAIRHAVEN SUBSTATION	57206	3.57	Dist
2009	LITTLE SILVER - 57454	57454	4.91	Dist
2009	FAIRHAVEN SUBSTATION	57205	5.99	Dist
2009	STIRLING37957(80257 0958)	37957	8.75	Dist
2009	MIDDLETOWN - 57460	57460	8.34	Dist
2009	FRENEAU - 47332	47332	4.96	Dist
2009	POPLAR SUBSTATION	57303	10.28	Dist
2009	BRIELLE - 57478	57478	6.71	Dist
2009	RUMSON SUBSTATION	54487	2.34	Dist
2009	KENVIL17598(80206 0493)	17598	5.92	Dist
2009	PINE BEACH - 67052	67052	8.95	Dist
2009	MOORE24588(80217 0674)	24588	7.07	Dist
2009	RUMSON SUBSTATION	57490	3.8	Dist
2009	CLINTON24671(80166 0195)	24671	9.68	Dist
2009	ATLANTIC HIGHLANDS - 53141	53141	3.97	Dist
2009	ISLAND HEIGHTS SUB	67454	8.31	Dist
2009	FRANKLIN17718(80186 0350)	17718	5.89	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2009	WARETOWN SUBSTATION	67356	10.38	Dist
2009	NORTH BRANCH27607(80231 0756)	27607	8.58	Dist
2009	ISLAND HEIGHTS SUB	67456	7.38	Dist
2009	BRIANT PARK33778(80156 0136)	33778	1.69	Dist
2009	NORTH BRANCH27606(80231 0755)	27606	6.36	Dist
2009	DEPOT - 57095	57095	3.01	Dist
2009	MIDDLETOWN - 57458	57458	7.55	Dist
2009	HIGHLAND - 53146	53146	3.03	Dist
2009	WARETOWN SUBSTATION	67359	10.96	Dist
2009	CHANGEBRIDGE 37793(80163 0176)	37793	7.93	Dist
2009	MIDDLETOWN - 57459	57459	4.93	Dist
2009	BRIANT PARK33776(80156 0134)	33776	2.34	Dist
2009	DOVER14503(80174 0251)	14503	3.34	Dist
2009	RUMSON SUBSTATION	54489	2.69	Dist
2009	GRANDIN SUB	27707	5.42	Dist
2009	WEST PORTAL24566(80272 1080)	24566	2.92	Dist
2009	FRENEAU - 47325	47325	6.97	Dist
2009	LITTLE SILVER - 57456	57456	5.99	Dist
2009	FRENEAU - 47327	47327	5.71	Dist
2009	HERBERTSVILLE - 57380	57380	2.78	Dist
2009	KITTATINNY SUB	17576	14.9	Dist
2009	JACKSONVILLE33827(80205 0476)	33827	4.94	Dist
2009	AZOPLATE27021(80148 0067)	27021	7.58	Dist
2009	CHAPIN ROAD37931(80164 0181)	37931	3.53	Dist
2009	BELMAR SUBSTAT	53356	3.56	Dist
2009	FAIRHAVEN SUBSTATION	54207	5	Dist
2009	WHITING - 69287	69287	22.68	Dist
2009	LITTLE SILVER - 54453	54453	3.05	Dist
2009	FAIRHAVEN SUBSTATION	54204	3.18	Dist
2009	CHAPIN ROAD37929(80164 0179)	37929	5.55	Dist
2009	THATCHER GLASS14684(80262 0999)	14684	7.24	Dist
2009	STONEYBROOK37651(80258 0964)	37651	10.08	Dist
2009	GREEN GROVE SUBST	57447	5.67	Dist
2009	RUMSON SUBSTATION	54488	1.58	Dist
2009	BELFORD - 57153	57153	6.24	Dist
2009	BRIELLE -57480	57480	4.66	Dist
2009	CEDARBRIDGE - 57020	57020	5.71	Dist
2009	ACADEMY37951(80141 0002)	37951	3.74	Dist
2009	HERBERTSVILLE - 57381	57381	4.76	Dist
2009	ACADEMY37954(80141 0005)	37954	4.68	Dist
2009	ISLAND HEIGHTS SUB	67457	8.05	Dist
2009	WARETOWN SUBSTATION	67358	8.28	Dist
2009	MOTTS CORNER - 67376	67376	9.6	Dist
2009	CHAPIN ROAD37930(80164 0180)	37930	7.36	Dist
2009	AZOPLATE27020(80148 0066)	27020	8.82	Dist
2009	LINCOLN PARK33944(80211 0558)	33944	3.87	Dist
2009	PHILLIPSBURG24663(80240 0808)	24663	3.73	Dist
2009	POPLAR SUBSTATION	57301	6.34	Dist
2009	PINEWALD - 64008	64008	1.67	Dist
2009	PINEWALD - 64009	64009	4.5	Dist
2009	LEISURE VILLAGE SUB	67526	5.57	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2009	RUMSON SUBSTATION	57491	3.15	Dist
2009	LEISURE VILLAGE SUB	67527	9.03	Dist
2009	AVON SUBSTATION	53027	2.51	Dist
2009	BRIANT PARK33777(80156 0135)	33777	1.25	Dist
2009	BRIANT PARK33779(80156 0137)	33779	1.21	Dist
2009	BRIELLE - 53481	53481	2.15	Dist
2009	CHANGEBRIDGE37791(80163 0174)	37791	2.99	Dist
2009	CHAPIN ROAD37928(80164 0178)	37928	6.09	Dist
2009	CROSSMAN SUBSTATION	43740	2.07	Dist
2009	EAST NEWTON14555(80176 0265)	14555	7.29	Dist
2009	EAST NEWTON14556(80176 0266)	14556	2.56	Dist
2009	GREEN GROVE SUBST	57449	8.43	Dist
2009	NORTH NEWTON	17508	12.84	Dist
2009	PARSIPPANY SUB	37677	4.25	Dist
2009	PHILLIPSBURG24677(80240 0810)	24677	3.72	Dist
2009	RACEWAY SUBSTATION	47423	6.28	Dist
2009	WAVERLY37991(80270 1066)	37991	2.21	Dist
2009	WHITINGS SUBSTATION	67285	16.33	Dist
2009	New Canton	47311	0	Dist
			811.12	

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2010	ACE SUB	33879	1.21	Dist
2010	AIRFIELD ROAD SUB	63135	0.19	Dist
2010	AIRFIELD ROAD SUB	63136	2.92	Dist
2010	AIRFIELD ROAD SUB	63137	0.79	Dist
2010	AIRFIELD ROAD SUB	63139	2.72	Dist
2010	AIRFIELD ROAD SUB	63140	0.21	Dist
2010	AIRFIELD ROAD SUB	63141	4.27	Dist
2010	ALLAMUCHY SUBSTATION	27733	71.72	Dist
2010	ALLAMUCHY SUBSTATION	27732	27.89	Dist
2010	ALLENHURST	53200	1.17	Dist
2010	ALLENHURST	53211	3.38	Dist
2010	ATLANTIC SUBSTATION	57423	5.36	Dist
2010	ATLANTIC SUBSTATION	57424	12.40	Dist
2010	BAPTISTOWN SUB	27720	16.20	Dist
2010	BAPTISTOWN SUB	27721	5.47	Dist
2010	BATH AVE SUBST	53001	1.64	Dist
2010	BATH AVE SUBST	53002	1.68	Dist
2010	BATH AVE SUBST	53003	3.47	Dist
2010	BATH AVE SUBST	53004	3.39	Dist
2010	BATH AVE SUBST	57005	1.11	Dist
2010	BATH AVE SUBST	57006	4.16	Dist
2010	BERKELEY HEIGHTS SUB	33760	3.37	Dist
2010	BERKELEY HEIGHTS SUB	33761	3.40	Dist
2010	BERKELEY HEIGHTS SUB	33762	1.24	Dist
2010	BERKELEY HEIGHTS SUB	33763	1.21	Dist
2010	BERKELEY HEIGHTS SUB	33764	2.41	Dist
2010	BRIELLE SUBSTATION	57482	2.36	Dist
2010	CAMPUS DRIVE SUB	37076	0.52	Dist
2010	CANOE BROOK SUB	33781	1.78	Dist
2010	CHAMBERS BROOK SUB	27011	2.42	Dist
2010	COLLINSVILLE SUBST	37772	2.61	Dist
2010	COLLINSVILLE SUBST	37773	1.71	Dist
2010	COLLINSVILLE SUBST	37774	5.15	Dist
2010	COLLINSVILLE SUBST	37775	1.91	Dist
2010	COLUMBIA SUBSTATION	24520	4.60	Dist
2010	COSTCO SUB	47880	9.71	Dist
2010	COSTCO SUB	47881	4.73	Dist
2010	DEEP RUN SUBSTATION	47701	5.91	Dist
2010	DEEP RUN SUBSTATION	47702	7.06	Dist
2010	DENVILLE SUB	14621	4.21	Dist
2010	DENVILLE SUB	14622	3.72	Dist
2010	DENVILLE SUB	14623	2.07	Dist
2010	DENVILLE SUB	14624	1.30	Dist
2010	DENVILLE SUB	14625	7.78	Dist
2010	EAST DOVER SUB	14510	2.70	Dist
2010	EAST DOVER SUB	14511	2.02	Dist
2010	EAST DOVER SUB	14512	6.05	Dist
2010	EAST DOVER SUB	14513	7.79	Dist
2010	ELBERON SUBSTATION	53133	0.65	Dist
2010	ELBERON SUBSTATION	53134	1.23	Dist
2010	ELBERON SUBSTATION	53135	2.11	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2010	MONTPELIER SUB	63121	0.16	Dist
2010	MONTPELIER SUB	63122	2.63	Dist
2010	MONTPELIER SUB	63123	1.60	Dist
2010	MONTPELIER SUB	63124	0.20	Dist
2010	MORRIS PARK	27051	5.51	Dist
2010	MORRIS PARK	27052	26.62	Dist
2010	MORRISTOWN SUB	37849	4.42	Dist
2010	MORRISTOWN SUB	37850	0.38	Dist
2010	MORRISTOWN SUB	37851	1.01	Dist
2010	MORRISTOWN SUB	37852	9.80	Dist
2010	MORRISTOWN SUB	37853	1.78	Dist
2010	MORRISTOWN SUB	37854	4.28	Dist
2010	MORRISTOWN SUB	37855	11.84	Dist
2010	MORRISTOWN SUB	37856	1.57	Dist
2010	MORRISTOWN SUB	37858	0.68	Dist
2010	MORRISTOWN SUB	37934	10.78	Dist
2010	MORRISTOWN SUB	37938	0.53	Dist
2010	MT ARLINGTON SUB	14604	2.82	Dist
2010	MT ARLINGTON SUB	17603	13.71	Dist
2010	MT ARLINGTON SUB	17605	8.97	Dist
2010	MT FERN SUBSTATION	17729	11.88	Dist
2010	MT FERN SUBSTATION	17730	6.97	Dist
2010	MT FERN SUBSTATION	17731	4.90	Dist
2010	MT FERN SUBSTATION	17732	7.31	Dist
2010	N.J. PULVERIZING	62016	0.31	Dist
2010	NESHANIC SUB	24580	14.14	Dist
2010	NESHANIC SUB	27451	10.95	Dist
2010	NESHANIC SUB	27452	8.18	Dist
2010	NESHANIC SUB	27453	8.97	Dist
2010	NETCONG SUB	14526	3.39	Dist
2010	NETCONG SUB	14527	5.29	Dist
2010	NETCONG SUB	14529	0.88	Dist
2010	NETCONG SUB	17570	4.08	Dist
2010	NETCONG SUB	17571	9.50	Dist
2010	NETCONG SUB	17572	7.56	Dist
2010	NETCONG SUB	17573	1.13	Dist
2010	NETCONG SUB	17574	6.76	Dist
2010	NEW PROSPECT ROAD	67900	5.07	Dist
2010	NEW PROSPECT ROAD	67901	5.63	Dist
2010	NEW PROSPECT ROAD	67902	7.06	Dist
2010	NEW PROSPECT ROAD	67903	8.42	Dist
2010	OLD BRIDGE SUB	47242	0.52	Dist
2010	OLD BRIDGE SUB	47305	5.60	Dist
2010	OLD BRIDGE SUB	47306	1.62	Dist
2010	ORTLEY BEACH SUB	63058	1.18	Dist
2010	ORTLEY BEACH SUB	63059	3.26	Dist
2010	ORTLEY BEACH SUB	63060	2.91	Dist
2010	PENNSYLVANIA AVE SUB	63116	4.16	Dist
2010	PENNSYLVANIA AVE SUB	63117	0.45	Dist
2010	PENNSYLVANIA AVE SUB	63118	1.61	Dist
2010	PERRYVILLE	27035	3.03	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2010	PINE BEACH SUB	64049	1.86	Dist
2010	PINE BEACH SUB	64050	4.05	Dist
2010	PINE BEACH SUB	64053	8.68	Dist
2010	PINEWALD SUBSTATION	67007	5.92	Dist
2010	PINEWALD SUBSTATION	67011	8.02	Dist
2010	RIVERDALE SUB	33886	3.48	Dist
2010	RIVERDALE SUB	33888	3.51	Dist
2010	RIVERDALE SUB	37885	7.44	Dist
2010	RIVERDALE SUB	37887	6.97	Dist
2010	RIVERDALE SUB	37889	3.41	Dist
2010	RIVERDALE SUB	37890	8.74	Dist
2010	ROCKAWAY SUB	14522	2.95	Dist
2010	ROCKAWAY SUB	14523	4.74	Dist
2010	ROCKAWAY SUB	14524	4.33	Dist
2010	ROCKAWAY SUB	14525	4.78	Dist
2010	ROCKAWAY SUB	14533	3.32	Dist
2010	ROCKTOWN SUBSTATION	24583	6.91	Dist
2010	ROCKTOWN SUBSTATION	24584	6.78	Dist
2010	ROCKTOWN SUBSTATION	24585	3.70	Dist
2010	ROCKTOWN SUBSTATION	24589	6.31	Dist
2010	S AMBOY SUBSTATION	43080	2.01	Dist
2010	S AMBOY SUBSTATION	43081	1.56	Dist
2010	S AMBOY SUBSTATION	43082	4.81	Dist
2010	SAXTON FALLS SUB	14769	0.15	Dist
2010	SAYREVILLE SUB	43263	2.29	Dist
2010	SAYREVILLE SUB	43264	2.66	Dist
2010	SAYREVILLE SUB	43268	3.30	Dist
2010	SAYREVILLE SUB	47267	5.66	Dist
2010	SEASIDE HEIGHTS SUB	63077	0.00	Dist
2010	STEWARTSVILLE SUB	24608	5.80	Dist
2010	STEWARTSVILLE SUB	24611	9.90	Dist
2010	STEWARTSVILLE SUB	27609	3.01	Dist
2010	SUMMIT SUBSTATION	33962	1.95	Dist
2010	SUMMIT SUBSTATION	33964	0.82	Dist
2010	SUMMIT SUBSTATION	33967	0.70	Dist
2010	SUMMIT SUBSTATION	33968	2.20	Dist
2010	SUMMIT SUBSTATION	33969	3.01	Dist
2010	SUMMIT SUBSTATION	33970	1.88	Dist
2010	TEXAS AVENUE SUB	63144	0.03	Dist
2010	TEXAS AVENUE SUB	63147	30.22	Dist
2010	TEXAS AVENUE SUB	63148	2.07	Dist
2010	WEST END SUBSTATION	53472	2.32	Dist
2010	WEST END SUBSTATION	53473	1.03	Dist
2010	WEST END SUBSTATION	53474	1.94	Dist
2010	WEST END SUBSTATION	53475	2.55	Dist
2010	WEST END SUBSTATION	53476	2.32	Dist
2010	WEST END SUBSTATION	53486	1.53	Dist
2010	WOODLAND SUBSTATION	57068	5.21	Dist
			969.58	

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2011	HOOPER AVE SUB	67260-C	1.96	Dist
2011	HOOPER AVE SUB	67261-C	0.62	Dist
2011	HOOPER AVE SUB	67262-C	1.44	Dist
2011	HOOPER AVE SUB	67263-C	1.86	Dist
2011	NEW LISBON SUB	67278-C	1.08	Dist
2011	NEW LISBON SUB	67312-C	4.40	Dist
2011	NEW LISBON SUB	67313-C	1.72	Dist
2011	NEW LISBON SUB	67314-C	1.71	Dist
2011	PLEASANT PLAINS SUB	67002-C	2.15	Dist
2011	PLEASANT PLAINS SUB	67003-C	0.79	Dist
2011	PLEASANT PLAINS SUB	67004-C	3.48	Dist
2011	PLEASANT PLAINS SUB	67005-C	0.54	Dist
2011	PLEASANT PLAINS SUB	67006-C	1.63	Dist
2011	HORNERSTOWN SUB	67292-C	0.76	Dist
2011	MANALAPAN SUB	47350-C	3.79	Dist
2011	MANALAPAN SUB	47351-C	5.49	Dist
2011	MILLHURST SUB	47415-C	1.19	Dist
2011	MILLHURST SUB	47416-C	1.37	Dist
2011	MILLHURST SUB	47417-C	1.19	Dist
2011	MILLHURST SUB	47418-C	0.98	Dist
2011	MILLHURST SUB	47419-C	4.25	Dist
2011	TWIN RIVERS SUB	47102-C	2.26	Dist
2011	TWIN RIVERS SUB	47103-C	1.79	Dist
2011	TWIN RIVERS SUB	47104-C	1.67	Dist
2011	FARMINGDALE SUBST	47089-C	2.86	Dist
2011	FARMINGDALE SUBST	47090-C	2.27	Dist
2011	MANCHESTER SUB	67210-C	3.51	Dist
2011	MANCHESTER SUB	67211-C	3.22	Dist
2011	EATONCREST SUB	54321-C	1.33	Dist
2011	EATONCREST SUB	54322-C	0.80	Dist
2011	EATONCREST SUB	54366-C	1.75	Dist
2011	EATONCREST SUB	54368-C	2.60	Dist
2011	EATONCREST SUB	57323-C	1.59	Dist
2011	EATONCREST SUB	57324-C	0.99	Dist
2011	OCEANVIEW SUBSTAT	59390-C	5.07	Dist
2011	OCEANVIEW SUBSTAT	59391-C	4.78	Dist
2011	APPLEGARTH SUB	47357-C	3.20	Dist
2011	APPLEGARTH SUB	47358-C	5.17	Dist
2011	CRANBURY SUB	47182-C	2.17	Dist
2011	CRANBURY SUB	47183-C	0.99	Dist
2011	CRANBURY SUB	47184-C	1.85	Dist
2011	CRANBURY SUB	47196-C	1.99	Dist
2011	MONROE SUBSTATION	47062-C	0.59	Dist
2011	MONROE SUBSTATION	47063-C	1.30	Dist
2011	MONROE SUBSTATION	47064-C	1.74	Dist
2011	MONROE SUBSTATION	47715-C	1.59	Dist
2011	MONROE SUBSTATION	47716-C	3.03	Dist
2011	MONROE SUBSTATION	47717-C	0.48	Dist
2011	ALLENWOOD SUBSTATION	57442-C	2.01	Dist
2011	ALLENWOOD SUBSTATION	57443-C	1.13	Dist
2011	DRUM POINT SUB	67268-C	1.64	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2011	DRUM POINT SUB	67269-C	0.58	Dist
2011	DRUM POINT SUB	67270-C	0.73	Dist
2011	GLENDOLA SUBSTATION	57736-C	1.05	Dist
2011	GLENDOLA SUBSTATION	57737-C	0.93	Dist
2011	GLENDOLA SUBSTATION	57738-C	1.80	Dist
2011	GLENDOLA SUBSTATION	57739-C	1.84	Dist
2011	STOCKTON SUBSTATION	53502-C	2.14	Dist
2011	STOCKTON SUBSTATION	53503-C	1.65	Dist
2011	STOCKTON SUBSTATION	53504-C	0.29	Dist
2011	WALL CHURCH SUB	57600-C	0.85	Dist
2011	WALL CHURCH SUB	57601-C	1.49	Dist
2011	DREW SUBSTATION	33902-M	0.36	Dist
2011	DREW SUBSTATION	33903-M	0.85	Dist
2011	DREW SUBSTATION	33904-M	0.42	Dist
2011	DREW SUBSTATION	33905-M	3.05	Dist
2011	DREW SUBSTATION	33906-M	0.58	Dist
2011	DREW SUBSTATION	33907-M	0.84	Dist
2011	GREYSTONE SUB	37693-M	2.54	Dist
2011	GREYSTONE SUB	37694-M	1.53	Dist
2011	GREYSTONE SUB	37696-M	2.57	Dist
2011	GREYSTONE SUB	37755-M	3.37	Dist
2011	GREYSTONE SUB	37756-M	3.03	Dist
2011	GREYSTONE SUB	37757-M	2.57	Dist
2011	GREYSTONE SUB	37758-M	1.23	Dist
2011	HALSEY SUB	37818-M	1.95	Dist
2011	HALSEY SUB	37819-M	0.65	Dist
2011	HALSEY SUB	37820-M	0.63	Dist
2011	HALSEY SUB	37821-M	1.11	Dist
2011	MORRIS PLAINS	33842-M	0.87	Dist
2011	MORRIS PLAINS	33843-M	1.03	Dist
2011	MORRIS PLAINS	33844-M	1.21	Dist
2011	MORRIS PLAINS	33845-M	0.98	Dist
2011	MOUNT PLEASANT SUB	37725-M	0.92	Dist
2011	MOUNT PLEASANT SUB	37922-M	1.36	Dist
2011	MOUNT PLEASANT SUB	37923-M	1.44	Dist
2011	MOUNT PLEASANT SUB	37924-M	1.28	Dist
2011	MOUNT PLEASANT SUB	37927-M	2.00	Dist
2011	PEQUANNOCK SUB	33875-M	1.44	Dist
2011	PEQUANNOCK SUB	33878-M	2.82	Dist
2011	PEQUANNOCK SUB	37876-M	0.94	Dist
2011	PEQUANNOCK SUB	37877-M	1.55	Dist
2011	POMPTON SUB	33749-M	1.92	Dist
2011	POMPTON SUB	33750-M	2.35	Dist
2011	POMPTON SUB	33751-M	2.41	Dist
2011	POMPTON SUB	33752-M	0.53	Dist
2011	POMPTON SUB	33753-M	3.16	Dist
2011	POMPTON SUB	33754-M	0.53	Dist
2011	TROY HILLS SUB	33908-M	1.55	Dist
2011	TROY HILLS SUB	33909-M	1.24	Dist
2011	TROY HILLS SUB	33910-M	0.56	Dist
2011	TROY HILLS SUB	33911-M	1.99	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2011	TROY HILLS SUB	33912-M	1.31	Dist
2011	TROY HILLS SUB	33913-M	1.07	Dist
2011	TROY HILLS SUB	33914-M	1.79	Dist
2011	TROY HILLS SUB	33915-M	0.68	Dist
2011	W DENVILLE SUB	14618-M	3.34	Dist
2011	W DENVILLE SUB	14619-M	1.22	Dist
2011	W DENVILLE SUB	14620-M	1.55	Dist
2011	BEACH GLEN	14691-M	0.84	Dist
2011	BEACH GLEN	14692-M	0.03	Dist
2011	BEACH GLEN	14693-M	1.85	Dist
2011	BEACH GLEN	14694-M	0.30	Dist
2011	BEACH GLEN	17689-M	1.80	Dist
2011	BEACH GLEN	17690-M	1.16	Dist
2011	DICKERSON SUB	14671-M	2.47	Dist
2011	DICKERSON SUB	14672-M	0.26	Dist
2011	DICKERSON SUB	14673-M	0.54	Dist
2011	DICKERSON SUB	14674-M	0.64	Dist
2011	DRAKESTOWN SUB	17100-M	4.22	Dist
2011	DRAKESTOWN SUB	17101-M	1.44	Dist
2011	FLANDERS SUB	17011-M	4.08	Dist
2011	FLANDERS SUB	17012-M	2.71	Dist
2011	FLANDERS SUB	17013-M	3.77	Dist
2011	FLANDERS SUB	17014-M	3.57	Dist
2011	HOPATCONG SUB	14635-M	1.43	Dist
2011	HOPATCONG SUB	14636-M	1.58	Dist
2011	HOPATCONG SUB	14637-M	2.40	Dist
2011	LANDING SUB	17740-M	2.68	Dist
2011	LANDING SUB	17742-M	1.60	Dist
2011	LANDING SUB	17743-M	1.35	Dist
2011	MENDHAM SUB	17647-M	1.99	Dist
2011	MENDHAM SUB	17648-M	2.12	Dist
2011	MENDHAM SUB	17649-M	1.12	Dist
2011	MENDHAM SUB	17650-M	1.89	Dist
2011	MORRIS SUBSTATION	14514-M	1.26	Dist
2011	MORRIS SUBSTATION	14515-M	1.84	Dist
2011	MORRIS SUBSTATION	14516-M	2.02	Dist
2011	MORRIS SUBSTATION	14517-M	1.13	Dist
2011	BUCKEYE SUB STATION	24070-M	1.27	Dist
2011	BUCKEYE SUB STATION	24071-M	1.02	Dist
2011	GILBERT 35KV	24548-M	2.98	Dist
2011	GILBERT 35KV	24569-M	0.90	Dist
2011	GREATER CROSSROADS	17594-M	2.88	Dist
2011	GREATER CROSSROADS	17595-M	3.64	Dist
2011	GREATER CROSSROADS	17596-M	1.55	Dist
2011	HAWKS SUB	27683-M	2.98	Dist
2011	HAWKS SUB	27684-M	2.53	Dist
2011	RINGOES SUB	24651-M	1.84	Dist
2011	RINGOES SUB	24652-M	0.49	Dist
2011	SOMERSET SUBSTATION	17698-M	2.77	Dist
2011	SOMERSET SUBSTATION	17699-M	1.10	Dist
2011	SOMERSET SUBSTATION	17700-M	0.85	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2011	SOMERSET SUBSTATION	17701-M	0.75	Dist
2011	BRANCHVILLE SUB	17630-M	1.30	Dist
2011	BRANCHVILLE SUB	17631-M	2.93	Dist
2011	BRANCHVILLE SUB	17632-M	2.80	Dist
2011	FRANKLIN SUBST	17719-M	0.03	Dist
2011	FRANKLIN SUBST	14537-M	2.57	Dist
2011	FRANKLIN SUBST	14539-M	1.69	Dist
2011	HOLIDAY LAKES SUB	17301-M	1.93	Dist
2011	HOLIDAY LAKES SUB	17302-M	1.68	Dist
2011	SPARTA SUB	17695-M	2.89	Dist
2011	SPARTA SUB	17696-M	2.19	Dist
2011	SPARTA SUB	17751-M	3.57	Dist
2011	VERNON SUB	17801-M	0.98	Dist
2011	VERNON SUB	17802-M	4.66	Dist
2011	VERNON SUB	17803-M	1.31	Dist
2011	VERNON SUB	17804-M	5.26	Dist
2011	CONVENT SUBSTATION	33798-M	0.21	Dist
2011	CONVENT SUBSTATION	37797-M	0.48	Dist
2011	CONVENT SUBSTATION	37800-M	0.78	Dist
2011	CONVENT SUBSTATION	37801-M	0.71	Dist
2011	CONVENT SUBSTATION	37802-M	1.87	Dist
2011	CSC	37423-M	0.84	Dist
2011	MOUNTAIN SUB	37643-M	2.65	Dist
2011	MOUNTAIN SUB	37640-M	1.44	Dist
2011	MOUNTAIN SUB	37642-M	3.15	Dist
2011	ALPHA SUB	24687-M	0.46	Dist
2011	ALPHA SUB	24688-M	2.89	Dist
2011	ALPHA SUB	24689-M	2.71	Dist
2011	ALPHA SUB	27690-M	4.07	Dist
2011	ALPHA SUB	27691-M	1.64	Dist
2011	HACKETTSTOWN SUB	14559-M	1.03	Dist
2011	HACKETTSTOWN SUB	14560-M	1.03	Dist
2011	HACKETTSTOWN SUB	14561-M	3.97	Dist
2011	HACKETTSTOWN SUB	14562-M	1.92	Dist
2011	HACKETTSTOWN SUB	14563-M	1.98	Dist
2011	WASHINGTON SUB	27708-M	1.06	Dist
2011	WASHINGTON SUB	27709-M	1.32	Dist
2011	WASHINGTON SUB	24507-M	0.89	Dist
2011	WASHINGTON SUB	24508-M	1.97	Dist
2011	WASHINGTON SUB	24509-M	2.67	Dist
2011	WASHINGTON SUB	24571-M	1.34	Dist
2011	WASHINGTON SUB	24572-M	1.52	Dist
2011	WASHINGTON SUB	24573-M	1.21	Dist
			356.639	

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	CHESTER SUB	17540-M	1.78	Dist
2012	CHESTER SUB	17541-M	3.04	Dist
2012	CHESTER SUB	17542-M	2.35	Dist
2012	CHESTER SUB	17543-M	2.29	Dist
2012	CHESTER SUB	17544-M	2.56	Dist
2012	HURDTOWN SUB	14613-M	0.27	Dist
2012	HURDTOWN SUB	14614-M	0.47	Dist
2012	HURDTOWN SUB	17785-M	3.19	Dist
2012	HURDTOWN SUB	17786-M	2.01	Dist
2012	BLAIRSTOWN SUB	17657-M	0.02	Dist
2012	BLAIRSTOWN SUB	17655-M	1.75	Dist
2012	BLAIRSTOWN SUB	17656-M	2.02	Dist
2012	BERNARDSVILLE SUB	17530-M	1.39	Dist
2012	BERNARDSVILLE SUB	17531-M	1.94	Dist
2012	BERNARDSVILLE SUB	17532-M	1.84	Dist
2012	BERNARDSVILLE SUB	17534-M	1.53	Dist
2012	BERNARDSVILLE SUB	17535-M	0.88	Dist
2012	LYONS SUBSTATION	17640-M	0.55	Dist
2012	LYONS SUBSTATION	17641-M	0.98	Dist
2012	LYONS SUBSTATION	17642-M	1.32	Dist
2012	TRAYNOR SUBSTATION	33974-M	1.38	Dist
2012	TRAYNOR SUBSTATION	33975-M	1.50	Dist
2012	TRAYNOR SUBSTATION	33976-M	1.88	Dist
2012	TRAYNOR SUBSTATION	33978-M	1.88	Dist
2012	TRAYNOR SUBSTATION	33980-M	1.96	Dist
2012	TRAYNOR SUBSTATION	37972-M	1.17	Dist
2012	TRAYNOR SUBSTATION	37973-M	2.43	Dist
2012	TRAYNOR SUBSTATION	39002-M	1.00	Dist
2012	TRAYNOR SUBSTATION	39003-M	1.31	Dist
2012	FOX HILL SUB	37808-M	2.25	Dist
2012	FOX HILL SUB	37809-M	0.20	Dist
2012	FOX HILL SUB	37810-M	1.96	Dist
2012	FOX HILL SUB	37811-M	1.18	Dist
2012	MOHAWK SUB	14644-M	0.70	Dist
2012	MOHAWK SUB	14645-M	2.08	Dist
2012	MOHAWK SUB	14646-M	4.90	Dist
2012	ALDERNEY SUB	37730-M	1.19	Dist
2012	ALDERNEY SUB	37731-M	1.40	Dist
2012	ALDERNEY SUB	37732-M	0.38	Dist
2012	ALDERNEY SUB	37734-M	0.00	Dist
2012	BOONTON SUB	33766-M	1.77	Dist
2012	BOONTON SUB	33771-M	1.78	Dist
2012	CEDAR KNOLLS SUB	37787-M	2.97	Dist
2012	CEDAR KNOLLS SUB	37788-M	0.86	Dist
2012	CEDAR KNOLLS SUB	37789-M	1.93	Dist
2012	CEDAR KNOLLS SUB	37790-M	0.96	Dist
2012	HASKELL SUB	37822-M	1.14	Dist
2012	HASKELL SUB	37823-M	0.60	Dist
2012	HASKELL SUB	37825-M	1.50	Dist
2012	EAST FLEMINGTON SUB	24544-M	3.04	Dist
2012	EAST FLEMINGTON SUB	24553-M	0.57	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	EAST FLEMINGTON SUB	24568-M	0.26	Dist
2012	EAST FLEMINGTON SUB	24575-M	1.55	Dist
2012	EAST FLEMINGTON SUB	24576-M	1.51	Dist
2012	EAST FLEMINGTON SUB	24577-M	2.66	Dist
2012	EAST FLEMINGTON SUB	27541-M	2.74	Dist
2012	EAST FLEMINGTON SUB	27542-M	3.10	Dist
2012	EAST FLEMINGTON SUB	27543-M	1.18	Dist
2012	FRENCHTOWN SUB	24546-M	1.35	Dist
2012	FRENCHTOWN SUB	24547-M	1.59	Dist
2012	FRENCHTOWN SUB	24549-M	1.64	Dist
2012	GILBOA SUBSTATION	24587-M	0.47	Dist
2012	OLD YORK SUB	27801-M	1.17	Dist
2012	OLD YORK SUB	27802-M	1.71	Dist
2012	STANTON SUBSTATION	27404-M	0.00	Dist
2012	STANTON SUBSTATION	24402-M	1.50	Dist
2012	STANTON SUBSTATION	24403-M	1.47	Dist
2012	STANTON SUBSTATION	27401-M	3.63	Dist
2012	WEST FLEMINGTON SUB	24530-M	1.79	Dist
2012	WEST FLEMINGTON SUB	24531-M	1.69	Dist
2012	WEST FLEMINGTON SUB	24532-M	0.71	Dist
2012	WEST FLEMINGTON SUB	27528-M	1.34	Dist
2012	WEST FLEMINGTON SUB	27529-M	1.78	Dist
2012	ANDOVER SUB	14704-M	1.45	Dist
2012	ANDOVER SUB	14705-M	1.75	Dist
2012	ANDOVER SUB	14706-M	2.09	Dist
2012	ANDOVER SUB	17702-M	1.18	Dist
2012	ANDOVER SUB	17703-M	1.75	Dist
2012	HAMBURG SUB	17557-M	1.30	Dist
2012	HAMBURG SUB	17558-M	2.43	Dist
2012	N NEWTON SUB	14549-M	0.16	Dist
2012	N NEWTON SUB	14550-M	2.06	Dist
2012	N NEWTON SUB	14551-M	0.64	Dist
2012	N NEWTON SUB	14552-M	1.24	Dist
2012	N NEWTON SUB	17508-M	2.80	Dist
2012	N NEWTON SUB	17509-M	1.28	Dist
2012	SUSSEX SUB	17565-M	2.44	Dist
2012	SUSSEX SUB	17566-M	1.98	Dist
2012	WOODRUFFS GAP SUB	14546-M	0.04	Dist
2012	WOODRUFFS GAP SUB	14545-M	0.32	Dist
2012	WOODRUFFS GAP SUB	17547-M	4.32	Dist
2012	WOODRUFFS GAP SUB	17548-M	3.36	Dist
2012	AIR REDUCTION	37701-M	0.01	Dist
2012	AIR REDUCTION	37702-M	0.75	Dist
2012	AIR REDUCTION	37859-M	0.51	Dist
2012	AIR REDUCTION	37860-M	1.11	Dist
2012	AIR REDUCTION	37861-M	2.33	Dist
2012	DEAD RIVER SUB	27501-M	2.29	Dist
2012	DEAD RIVER SUB	27502-M	0.81	Dist
2012	DEAD RIVER SUB	27503-M	2.64	Dist
2012	DEAD RIVER SUB	27504-M	3.48	Dist
2012	FDU SUBSTATION	33806-M	0.02	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	FDU SUBSTATION	33807-M	1.43	Dist
2012	GREEN VILLAGE SUB	37813-M	1.35	Dist
2012	GREEN VILLAGE SUB	37814-M	1.48	Dist
2012	NEW PROVIDENCE	33862-M	1.00	Dist
2012	NEW PROVIDENCE	33863-M	0.41	Dist
2012	NEW PROVIDENCE	33864-M	0.61	Dist
2012	NEW PROVIDENCE	33865-M	1.04	Dist
2012	NEW PROVIDENCE	33866-M	0.56	Dist
2012	VALLEY VIEW SUB	33983-M	1.19	Dist
2012	VALLEY VIEW SUB	33984-M	3.07	Dist
2012	VALLEY VIEW SUB	33985-M	1.20	Dist
2012	VALLEY VIEW SUB	33986-M	0.65	Dist
2012	VALLEY VIEW SUB	33987-M	1.39	Dist
2012	MARBLE HILL SUB	24701-M	0.49	Dist
2012	MARBLE HILL SUB	24702-M	1.74	Dist
2012	MARBLE HILL SUB	24703-M	2.41	Dist
2012	NEWBURGH SUB	17776-M	1.15	Dist
2012	NEWBURGH SUB	17777-M	2.56	Dist
2012	NEWBURGH SUB	17778-M	2.12	Dist
2012	NEWBURGH SUB	17779-M	3.65	Dist
2012	PORT MURRAY SUB	27730-M	1.13	Dist
2012	PORT MURRAY SUB	27731-M	1.63	Dist
2012	CRAWFORDS CORNER SUB	47405-C	1.40	Dist
2012	CRAWFORDS CORNER SUB	47406-C	1.88	Dist
2012	CRAWFORDS CORNER SUB	47407-C	2.13	Dist
2012	CRAWFORDS CORNER SUB	47408-C	1.27	Dist
2012	FAIRVIEW SUBST	57385-C	1.77	Dist
2012	FAIRVIEW SUBST	57386-C	0.61	Dist
2012	FAIRVIEW SUBST	57387-C	0.98	Dist
2012	FAIRVIEW SUBST	57388-C	0.71	Dist
2012	LINCROFT SUB	57167-C	1.88	Dist
2012	LINCROFT SUB	57168-C	1.57	Dist
2012	LINCROFT SUB	57169-C	4.62	Dist
2012	LINCROFT SUB	57170-C	1.45	Dist
2012	BRADEVELT SUBSTATION	47170-C	0.60	Dist
2012	BRADEVELT SUBSTATION	47171-C	0.61	Dist
2012	BRADEVELT SUBSTATION	47172-C	1.19	Dist
2012	BRADEVELT SUBSTATION	47173-C	0.93	Dist
2012	GORDONS CORNER SUB	47379-C	1.19	Dist
2012	GORDONS CORNER SUB	47380-C	0.98	Dist
2012	GORDONS CORNER SUB	47381-C	2.21	Dist
2012	GORDONS CORNER SUB	47382-C	2.24	Dist
2012	GORDONS CORNER SUB	47383-C	1.89	Dist
2012	GORDONS CORNER SUB	47384-C	0.36	Dist
2012	GORDONS CORNER SUB	47385-C	0.63	Dist
2012	ALLENHURST	53194-C	1.25	Dist
2012	ALLENHURST	53195-C	2.43	Dist
2012	ALLENHURST	53196-C	0.65	Dist
2012	ALLENHURST	53197-C	0.04	Dist
2012	ALLENHURST	53198-C	0.20	Dist
2012	ALLENHURST	53199-C	0.38	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	ALLENHURST	53201-C	1.50	Dist
2012	ASBURY PARK SUBST	53463-C	2.09	Dist
2012	ASBURY PARK SUBST	53465-C	0.58	Dist
2012	ASBURY PARK SUBST	53466-C	1.29	Dist
2012	ASBURY PARK SUBST	53468-C	1.97	Dist
2012	ASBURY PARK SUBST	53470-C	1.09	Dist
2012	ASBURY PARK SUBST	57518-C	1.09	Dist
2012	ASBURY PARK SUBST	57519-C	1.08	Dist
2012	BRADLEY BEACH SUBST	53223-C	1.66	Dist
2012	BRADLEY BEACH SUBST	53224-C	1.08	Dist
2012	BRADLEY BEACH SUBST	53225-C	1.61	Dist
2012	BRADLEY BEACH SUBST	53226-C	1.08	Dist
2012	BRADLEY BEACH SUBST	53227-C	0.96	Dist
2012	BRADLEY BEACH SUBST	53228-C	2.06	Dist
2012	BRADLEY BEACH SUBST	53229-C	1.89	Dist
2012	BRADLEY BEACH SUBST	57221-C	1.51	Dist
2012	BRANCHPORT SUB	53430-C	1.48	Dist
2012	BRANCHPORT SUB	53431-C	1.85	Dist
2012	BRANCHPORT SUB	53432-C	0.56	Dist
2012	BRANCHPORT SUB	53433-C	3.07	Dist
2012	BRANCHPORT SUB	53434-C	3.14	Dist
2012	HAMILTON SUBSTATION	54274-C	0.69	Dist
2012	HAMILTON SUBSTATION	54275-C	2.76	Dist
2012	NEPTUNE SUBSTATION	53493-C	1.47	Dist
2012	NEPTUNE SUBSTATION	53494-C	1.39	Dist
2012	NEPTUNE SUBSTATION	53495-C	0.30	Dist
2012	NEPTUNE SUBSTATION	53496-C	0.97	Dist
2012	NEPTUNE SUBSTATION	57497-C	0.49	Dist
2012	NEPTUNE SUBSTATION	57498-C	1.86	Dist
2012	WHITESVILLE SUB	53270-C	2.41	Dist
2012	WHITESVILLE SUB	53271-C	1.88	Dist
2012	WHITESVILLE SUB	53349-C	0.92	Dist
2012	WHITESVILLE SUB	53350-C	1.84	Dist
2012	JERSEYVILLE SUBSTA	44479-C	2.66	Dist
2012	JERSEYVILLE SUBSTA	44480-C	3.60	Dist
2012	JERSEYVILLE SUBSTA	44481-C	2.86	Dist
2012	JERSEYVILLE SUBSTA	47482-C	3.24	Dist
2012	JERSEYVILLE SUBSTA	47483-C	0.54	Dist
2012	LARRABEE SUBSTATION	67345-C	2.72	Dist
2012	LARRABEE SUBSTATION	67346-C	3.07	Dist
2012	LARRABEE SUBSTATION	67347-C	3.18	Dist
2012	LARRABEE SUBSTATION	67348-C	1.21	Dist
2012	LARRABEE SUBSTATION	67349-C	0.73	Dist
2012	LARRABEE SUBSTATION	67350-C	1.09	Dist
2012	LARRABEE SUBSTATION	67351-C	2.33	Dist
2012	LARRABEE SUBSTATION	67352-C	2.00	Dist
2012	LACEY SUBSTATION	67398-C	1.56	Dist
2012	LACEY SUBSTATION	67399-C	2.67	Dist
2012	LACEY SUBSTATION	67400-C	1.45	Dist
2012	LACEY SUBSTATION	67401-C	1.74	Dist
2012	LAKEHURST SUBSTATION	64324-C	1.92	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	LAKEHURST SUBSTATION	64325-C	0.63	Dist
2012	LAKEHURST SUBSTATION	64326-C	1.92	Dist
2012	LAKEHURST SUBSTATION	64327-C	1.42	Dist
2012	LAKEHURST SUBSTATION	69328-C	10.20	Dist
2012	LAKEHURST SUBSTATION	69329-C	7.76	Dist
2012	OYSTER CREEK SUB	69360-C	0.42	Dist
2012	OYSTER CREEK SUB	69361-C	5.33	Dist
2012	HYSON SUBSTATION	67306-C	1.14	Dist
2012	HYSON SUBSTATION	67307-C	2.17	Dist
2012	HYSON SUBSTATION	67308-C	1.55	Dist
2012	HYSON SUBSTATION	67309-C	1.40	Dist
2012	HYSON SUBSTATION	67310-C	1.46	Dist
2012	HYSON SUBSTATION	67311-C	4.66	Dist
2012	MANITOU SUBSTATION	67501-C	2.40	Dist
2012	MANITOU SUBSTATION	67502-C	1.30	Dist
2012	MANITOU SUBSTATION	67503-C	0.80	Dist
2012	MANITOU SUBSTATION	69504-C	3.61	Dist
2012	MANITOU SUBSTATION	69505-C	5.09	Dist
2012	MANITOU SUBSTATION	69506-C	6.49	Dist
2012	MANITOU SUBSTATION	69507-C	4.67	Dist
2012	MANITOU SUBSTATION	69508-C	3.74	Dist
2012	MANITOU SUBSTATION	69509-C	2.45	Dist
2012	MANITOU SUBSTATION	69510-C	1.20	Dist
2012	CAPEHART SUBSTATION	67126-C	0.30	Dist
2012	CAPEHART SUBSTATION	67127-C	0.08	Dist
2012	CAPEHART SUBSTATION	67128-C	0.79	Dist
2012	CAPEHART SUBSTATION	67129-C	0.50	Dist
2012	CAPEHART SUBSTATION	67130-C	0.17	Dist
2012	CAPEHART SUBSTATION	67131-C	0.50	Dist
2012	HAYTI SUBSTATION	47390-C	1.17	Dist
2012	HAYTI SUBSTATION	47391-C	1.51	Dist
2012	HAYTI SUBSTATION	47392-C	2.81	Dist
2012	MC GUIRE SUBSTATION	67047-C	3.87	Dist
2012	MC GUIRE SUBSTATION	67412-C	0.00	Dist
2012	NEW CANTON	47310-C	0.00	Dist
2012	NEW CANTON	47311-C	5.00	Dist
2012	UPTON SUBSTATION	67293-C	1.20	Dist
2012	UPTON SUBSTATION	67294-C	6.57	Dist
2012	UPTON SUBSTATION	67295-C	1.14	Dist
2012	UPTON SUBSTATION	67303-C	3.68	Dist
2012	ENGLISHTOWN SUBSTAT	47076-C	2.45	Dist
2012	ENGLISHTOWN SUBSTAT	47077-C	3.56	Dist
2012	ENGLISHTOWN SUBSTAT	47078-C	0.40	Dist
2012	FREEHOLD SUB	44091-C	1.16	Dist
2012	FREEHOLD SUB	44093-C	1.36	Dist
2012	FREEHOLD SUB	44094-C	0.40	Dist
2012	MCGRAW HILL SUB	43296-C	1.05	Dist
2012	MCGRAW HILL SUB	43298-C	1.14	Dist
2012	MCGRAW HILL SUB	47297-C	1.23	Dist
2012	PRINCETON SUB	43498-C	0.80	Dist
2012	PRINCETON SUB	43499-C	2.29	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	PRINCETON SUB	43500-C	2.02	Dist
2012	WINDSOR SUB	43200-C	3.20	Dist
2012	WINDSOR SUB	43201-C	3.39	Dist
2012	WINDSOR SUB	43202-C	0.08	Dist
2012	WINDSOR SUB	43203-C	0.08	Dist
2012	WINDSOR SUB	47198-C	1.85	Dist
2012	WINDSOR SUB	47199-C	3.62	Dist
2012	WYCKOFF SUBSTATION	43189-C	1.02	Dist
2012	WYCKOFF SUBSTATION	43190-C	1.01	Dist
2012	WYCKOFF SUBSTATION	43191-C	0.14	Dist
2012	WYCKOFF SUBSTATION	47193-C	5.46	Dist
2012	WYCKOFF SUBSTATION	47194-C	0.81	Dist
2012	WYCKOFF SUBSTATION	47195-C	1.28	Dist
2012	METEDECONK SUB	67366-C	0.00	Dist
2012	METEDECONK SUB	67367-C	0.00	Dist
2012	METEDECONK SUB	67368-C	0.00	Dist
2012	SOUTH LAKEWOOD SUB	67490-C	2.59	Dist
2012	SOUTH LAKEWOOD SUB	67491-C	2.93	Dist
2012	SOUTH LAKEWOOD SUB	67492-C	5.32	Dist
2012	SOUTH LAKEWOOD SUB	67493-C	1.96	Dist
2012	SOUTH LAKEWOOD SUB	67494-C	4.21	Dist
2012	SOUTH LAKEWOOD SUB	67495-C	2.68	Dist
2012	VANHISEVILLE SUB	67316-C	1.75	Dist
2012	VANHISEVILLE SUB	67317-C	1.07	Dist
2012	VANHISEVILLE SUB	67319-C	5.61	Dist
2012	VERMONT AVE SUB	67611-C	1.76	Dist
2012	VERMONT AVE SUB	67612-C	1.22	Dist
2012	BROWN TOWN SUB	47744-C	1.01	Dist
2012	BROWN TOWN SUB	47745-C	2.08	Dist
2012	BROWN TOWN SUB	47746-C	0.54	Dist
2012	BROWN TOWN SUB	47747-C	1.41	Dist
2012	JAMESBURG SUB	43238-C	0.71	Dist
2012	LAURENCE HARBOR SUB	47179-C	1.48	Dist
2012	LAURENCE HARBOR SUB	47180-C	0.22	Dist
2012	LAURENCE HARBOR SUB	47181-C	1.23	Dist
2012	SAYREWOODS SUB	43449-C	0.97	Dist
2012	SAYREWOODS SUB	43450-C	1.45	Dist
2012	SPOTSWOOD SUB	47370-C	0.55	Dist
2012	SPOTSWOOD SUB	47371-C	0.46	Dist
2012	SPOTSWOOD SUB	43373-C	1.12	Dist
2012	SPOTSWOOD SUB	47374-C	2.46	Dist
2012	SPOTSWOOD SUB	47375-C	2.57	Dist
2012	TEXAS ROAD SUB	47285-C	1.09	Dist
2012	TEXAS ROAD SUB	47286-C	2.86	Dist
2012	TEXAS ROAD SUB	47287-C	1.29	Dist
2012	TEXAS ROAD SUB	47288-C	0.94	Dist
2012	BENNETT SUBSTATION	57248-C	2.17	Dist
2012	BENNETT SUBSTATION	57249-C	0.54	Dist
2012	HERBERTSVILLE SUB	57382-C	4.10	Dist
2012	HERBERTSVILLE SUB	57383-C	3.40	Dist
2012	LANES MILL SUB	57315-C	1.13	Dist

Year	Substation Desc	Circuit (i)	Miles (ii)	Voltage (iii)
2012	SPRING LAKE HTS SUB	53138-C	2.28	Dist
2012	SPRING LAKE HTS SUB	53139-C	1.38	Dist
2012	SPRING LAKE HTS SUB	57140-C	1.17	Dist
2012	SPRING LAKE HTS SUB	57252-C	0.79	Dist
2012	RINGOES SUB	24652-M	0.49	Dist
2012	RINGOES SUB	24653-M	3.01	Dist
2012	RINGOES SUB	27655-M	3.56	Dist
2012	MILLBURN SUB	33831-M	2.05	Dist
2012	MILLBURN SUB	33832-M	0.70	Dist
2012	MILLBURN SUB	33833-M	1.41	Dist
2012	MILLBURN SUB	33834-M	0.68	Dist
2012	MILLBURN SUB	33835-M	1.29	Dist
2012	MILLBURN SUB	33836-M	1.04	Dist
2012	MILLBURN SUB	33837-M	0.91	Dist
2012	MILLBURN SUB	33838-M	2.06	Dist
2012	SHORT HILLS	33893-M	2.74	Dist
2012	SHORT HILLS	33894-M	0.80	Dist
2012	SHORT HILLS	33895-M	0.76	Dist
2012	SHORT HILLS	37896-M	1.67	Dist
2012	SHORT HILLS	37897-M	1.45	Dist
2012	PEQUEST RIVER SUB	27665-M	2.59	Dist
2012	PEQUEST RIVER SUB	27666-M	2.47	Dist
2012	PEQUEST RIVER SUB	27667-M	0.07	Dist
			631.36	

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases In and Other Adjustments to its Rates and Charges for Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-88 On page 43 of Attachment 2 to the Company's response to RCR-REL-1 a footnote addresses the distribution circuits and the transmission corridors that received vegetation management in 2010 as follows:

All circuits were inspected and trimmed as necessary, while certain limited amounts of trimming deemed not immediately necessary were deferred for follow-up in a subsequent vegetation management cycle. For instance, any deferred trimming of sub-transmission voltages has been completed by the date of this Report. Any remaining deferred distribution trimming is being addressed throughout 2011.

a. Please describe for how many miles of distribution circuits trimming was deferred from 2010 into 2011 or later. Please break this figure down by operating area.
b. Please describe for how many miles of transmission corridor trimming was deferred from 2010 into 2011. Please break this figure down by operating area.
c. For the miles of distribution circuits for which trimming was deferred from 2010 into 2011 or later, please identify how many of these miles were trimmed in 2011 and how many of these miles were trimmed in 2012. Please break these figures down by operating area.
d. Please describe the criteria used to determine trimming was not immediately necessary.

Response:

a. As the Company reported in its 2010 and 2011 ASPR certain limited amounts of trimming was deferred for completion in a subsequent cycle year, with most completed by December 31, 2011 and a small amount of remaining work deferred into 2012 due to the impact of Hurricane Irene and the October 2011 snowstorm. It should also be recalled that in the Company's response to RCR-REL-75, it was explained that "[t]he specific mileage from 2009 and 2010 that was deferred to subsequent years is not tracked by the Company's Internet Vegetation Management System ("IVMS") and does not appear in IVMS." However, the JCP&L Vegetation Management department undertook a manual effort based on the records for the work performed to be able to make the following determinations:

In terms of distribution circuits, the deferred mileage from 2010 into 2011 is estimated to be 657 miles northern ("NNJ") and 245 miles central ("CNJ") operating areas.

b. There were no transmission corridors deferred from 2010 into 2011.

c. The miles deferred from 2010 were completed by December 31, 2011.

d. All circuits were visually inspected. Trimming was not immediately necessary when tree conditions and/or growth did not pose an impending hazard.

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases In and Other Adjustments to its Rates and Charges for Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-89 On page 44 of Attachment 3 to the Company's response to RCR-REL-1 a foot note addresses the distribution circuits and the transmission corridors that received vegetation management in 2010 as follows:

All circuits were inspected and trimmed as necessary (including deferred trimming from 2010 as was explained in the 2010 Report), except for certain limited amounts of trimming that could not be completed due to the schedule interruption caused by Hurricane Irene and the October Snow Storm major events and which was then deferred for completion during 2012. The limited amount of trimming deferred from 2011 have been completed by the date of this Report.

a. Please describe for how many miles of distribution circuits trimming was deferred from 2011 into 2012. Please break this figure down by operating area.

b. Please describe for how many miles of transmission corridor trimming was deferred from 2011 into 2012. Please break this figure down by operating area.

Response: PLEASE NOTE that it is assumed that this request addresses the distribution circuits and the transmission corridors that received vegetation management in 2011 and not 2010 as indicated since RCR-REL-88 addresses 2010.

a. As the Company reported in its 2010 and 2011 ASPR certain limited amounts of trimming was deferred for completion in a subsequent cycle year, with most completed by December 31, 2011 and a small amount of remaining work deferred into 2012 due to the impact of Hurricane Irene and the October 2011 snowstorm. It should also be recalled that in the Company's response to RCR-REL-75, it was explained that "[t]he specific mileage from 2009 and 2010 that was deferred to subsequent years is not tracked by the Company's Internet Vegetation Management System ("IVMS") and … does not appear in IVMS." However, the JCP&L Vegetation Management department undertook a manual effort based on the records for the work performed to be able to make the following determinations:

In terms of distribution circuits, the deferred mileage is estimated from 2011 into 2012 to be 255 miles northern ("NNJ") and 161 miles central ("CNJ") operating areas.

b. There were no transmission corridors deferred from 2011 into 2012.

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases In and Other Adjustments to its Rates and Charges for Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

BPU Docket No. ER12111052
OAL Docket No. PUC 16310-2012N

RESPONSES TO DATA REQUESTS

RCR-REL-90 Attachment 1 to the Company's response to RCR-REL-1, the 2009 Annual System Performance Report, does not appear to mention the deferral of the trimming of distribution circuits or of transmission corridors from 2009 into a subsequent year. However, the Direct Testimony of Ralph Hillmer states, on page 11 (lines 4-7), that some of the planned trimming work for 2009 and 2010 was deferred to a subsequent year.

a. Please describe for how many miles of distribution circuits for which trimming was deferred from 2009 into 2010 or later. Please break this figure down by operating area.

b. Please describe for how many miles of transmission corridor trimming was deferred from 2009 into 2010. Please break this figure down by operating area.

c. For the miles of distribution circuits for which trimming was deferred from 2009 into 2010 or later, please identify how many of these miles were trimmed in 2010 and how many of these miles were trimmed in 2011. Please break these figures down by operating area.

Response: a. As the Company reported in its 2010 and 2011 ASPR certain limited amounts of trimming was deferred for completion in a subsequent cycle year, with most completed by December 31, 2011 and a small amount of remaining work deferred into 2012 due to the impact of Hurricane Irene and the October 2011 snowstorm. It should also be recalled that in the Company's response to RCR-REL-75, it was explained that "[t]he specific mileage from 2009 and 2010 that was deferred to subsequent years is not tracked by the Company's Internet Vegetation Management System ("IVMS") and … does not appear in IVMS." However, the JCP&L Vegetation Management department undertook a manual effort based on the records for the work performed to be able to make the following determinations:

> *In terms of distribution circuits, the deferred mileage from 2009 into 2010 or 2011 is estimated to be 444 miles northern ("NNJ") and 691 miles central ("CNJ") operating areas.*

b. There were no transmission corridors deferred from 2009 into 2010.

c. By the end of 2010, 249 miles were completed in NNJ and 398 miles were completed in CNJ. By the end of 2011, 195 miles were completed in NNJ and 293 miles were completed in CNJ.