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**JAMES A. MCGEE**
ASSOCIATE GENERAL COUNSEL
PROGRESS ENERGY SERVICE COMPANY, LLC

August 18, 2003

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COMMISSION CLERK
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HAND DELIVERY

030834-EI

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Request of Progress Energy Florida to exclude an outage event from its Annual Distribution Service Reliability Report for 2003.

Dear Ms. Bayó:

Enclosed for filing in the subject docket on behalf of Progress Energy Florida, Inc., formerly Florida Power Corporation, are an original and fifteen copies of the subject Request.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. A 3½ inch diskette containing the above-referenced document in WordPerfect format is also enclosed. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/scc
Enclosures

cc: Office of Public Counsel

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

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100 Central Avenue (33701) • Post Office Box 14042 (33733) • St. Petersburg, Florida
Phone: 727.820.5184 • Fax: 727.820.5519 • Email: james.mcgee@pgnmail.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

| | |
|---|---|
| In re: Request of Progress Energy Florida to exclude an Outage Event from its Annual Distribution Service Reliability Report for 2003. | Docket No. ____________<br>Submitted for filing: August 18, 2003 |

## <u>REQUEST TO EXCLUDE OUTAGE EVENT</u>

Progress Energy Florida, Inc., formerly Florida Power Corporation (Progress Energy or the Company), pursuant to Rule 25-6.0455(3), F.A.C., hereby requests the Florida Public Service Commission (the Commission) to approve the exclusion of the outage event described herein from the Company's Annual Distribution Service Reliability Report for calendar year 2003. In support of its request, Progress Energy states as follows:

1. Commission Rule 25-6.0455(1) requires utilities to file an Annual Distribution Service Reliability Report for each calendar year by March 1st of the following year. The Report provides extensive distribution outage event data and related calculations of reliability indices, as specified in Commission Forms PSC/ECR 102-1, 102-2 and 102-3. Subsection (2) of the Rule allows a utility to exclude from its Annual Distribution Service Reliability Report outage events caused by certain enumerated conditions. Finally, Subsection (3) provides that a utility may also request the exclusion of an outage event not specifically enumerated in Subsection (2) from its Report, and goes on to state: "The Commission will approve the request if the utility is able to demonstrate that the outage was not within the

.ity's control, and that the utility could not reasonably have prevented the outage." This request by Progress Energy is submitted for Commission approval pursuant to the provisions of Subsection (3).

2. The outage event subject to this request resulted from a storm front that developed in the Gulf of Mexico on July 18, 2003 and made landfall on the central west coast of Florida at approximately 3 p.m. The storm continued to intensify as it moved easterly across the state through the center of Progress Energy's service territory, including the greater Orlando area, and finally dissipated when it reached the east coast around midnight. By that time, it had become one of the most severe non-tropical storms ever experienced in the Company's service area. The effects of the storm, which continued well into July 19th, produced 435 outages on 248 feeder lines, or 21% of all feeder lines on Progress Energy's system. These outages resulted in service interruptions to 19,568 customers and equate to a system average interruption per customer (SAIDI) of 2.11 minutes.

3. Several objective measures confirm the severity of the weather system that caused this outage event. One such measure of severity is the frequency of lightning strikes ("flash count" or "flash density"), as measured by the National Lightning Detection Network. While lightning, in and of itself, is one of the principal causes of outages associated with a weather disturbance, the flash count data it generates also provides one of the few readily available, objective and quantifiable measures of a storm's overall intensity. As can be seen from the first graph in the attached Exhibit A, the weather system in question was extraordinary, even for the storm-

intensive summer period when this outage event occurred. The July 18th storm produced a record flash count of 7,112 lightning strikes within the Progress Energy system, which dwarfed the previous record of 5,333 strikes by fully 33%. Exhibit A's second graph provides detail for July 2003 that cannot be seen in the first graph because of its scale. For perspective, Exhibit B shows a series of seven daily composite radar flash density maps for the surrounding week of July 15 through July 21, which itself was well above the average flash density even without the July 18th storm.

4. Another objective measure of a weather system's severity is the recently adopted IEEE methodology for identifying "major events" affecting distribution reliability, which will be incorporated into IEEE Publication 1366, *Full-Use Guide on Electric Power Distribution Reliability Indices*. The IEEE white paper *Classification of Major Event Days*, which describes the development and application of this methodology, is attached as Exhibit C. The impetus for developing the methodology was IEEE's recognition that "both internal and external goals have been set around reliability performance, yet there has been no uniform methodology for removing events that are so far away from normal performance that they are known as outliers." In response to this concern, IEEE developed a statistics-based methodology to identify these outliers, referred to as Major Event Days (MEDs), so that reliability indices can be normalized to exclude events beyond the control and the design and/or operational limits of a utility.

5. Under the IEEE methodology, which Exhibit C describes in greater detail, a MED is a day in which a utility's daily SAIDI exceeds a threshold value equal to 2.5 standard deviations above the mean natural logarithm of the daily SAIDI values over the preceding five-year period. Assuming a standard bell shaped distribution, a threshold set at 2.5 standard deviations above the mean represents a SAIDI value greater than 99% of all daily SAIDI values over the five-year period. Using this methodology, Progress Energy's MED threshold is a daily SAIDI of 1.93 minutes. As noted in paragraph 2 above, the Company's SAIDI for the 24-hour period from Noon, July 18 to Noon, July 19 was 2.11 minutes. This is not only well above the MED threshold, but is also one of the highest daily SAIDI values ever recorded by the Company.

6. The feeder line outages and service interruptions caused by the severity of the July 18th storm occurred despite the effective measures that Progress Energy has implemented to prevent or mitigate storm-related outages.[1] Storms of this magnitude and intensity are beyond the design and operational limits of the Company's distribution system, as they should be. The costs associated with designing and operating a system capable of withstanding such an extreme and unusual event would, in Progress Energy's judgement, far exceed the infrequent

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[1] One of the most significant of these measures, Progress Energy's lightning protection program, was the subject of a comprehensive Staff audit of the state's four investor-owned utilities. The final audit report, issued in February 2002, did not recommend any changes in the Company's lightning mitigation practices. (The only recommended improvement specific to the Company concerned updating internal manuals.) Overall, the audit showed the Company to be innovative and pace setting in the use of the latest technology and engineering practices for lightning protection.

benefit to the Company's general body of customers, who would ultimately be responsible for these costs.

7. In response to the high level of service outages caused by the July 18th storm, Progress Energy mobilized all active and off-duty crews and equipment from the local distribution operations center, supplemented by other support personnel such as meter readers, servicemen, and supervisory and staff personnel. In addition, off-duty crews from five remote distribution operations centers, as well as independent contractor crews, were activated and were dispatched with a compliment of 26 bucket trucks to assist in the restoration of service. All crews worked non-stop until the restoration of service was largely completed at approximately 5 p.m. on July 19th, at which time the remote crews were released to return home. The local crews continued on the job until approximately 8 a.m. on July 20th when final restoration activities were completed.

8. The foregoing demonstrates that the outage event associated with the severe weather system of July 18, 2003 was not within Progress Energy's control and that the Company could not reasonably have prevented the outage event. Indeed, given the extreme and highly unusual nature of this weather system, Progress Energy submits that it would be cost prohibitive and contrary to the best interests of its customers to attempt to design a distribution system capable of withstanding such a storm.

WHEREFORE, Progress Energy respectfully requests that, for the reasons set forth above, the Commission grant this request and approve the exclusion of the outage event on July 18 and 19, 2003 from its Distribution Service Reliability Report for calendar year 2003.

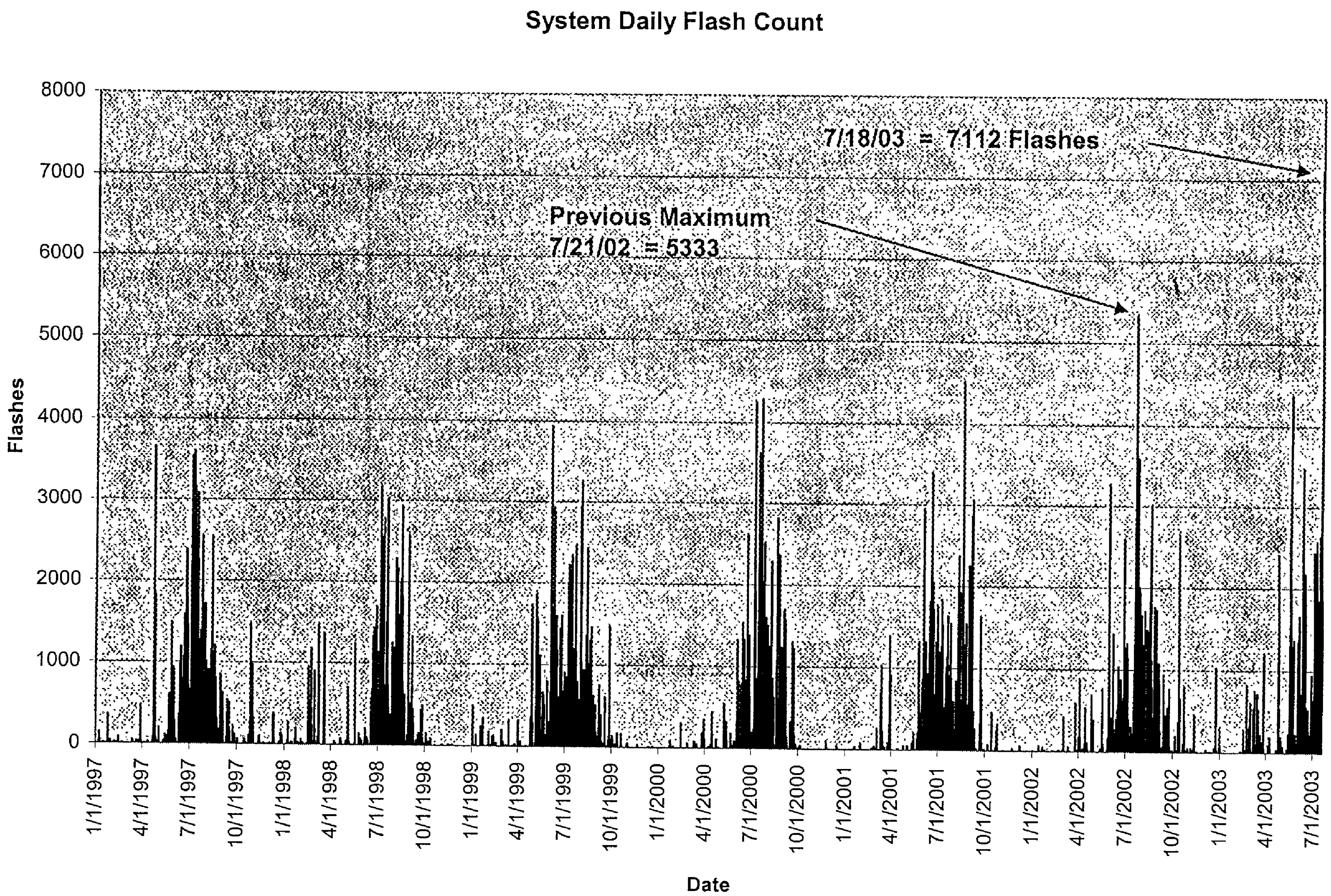
Respectfully submitted,

James A. McGee
Associate General Counsel
Progress Energy Service Company, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

Attorney for
PROGRESS ENERGY FLORIDA, INC.

**EXHIBIT A**

## HISTORIC DAILY LIGHTNING FLASH COUNT FOR THE PROGRESS ENERGY SYSTEM


System Daily Flash Count
7/18/03 = 7112 Flashes
Previous Maximum
7/21/02 = 5333
Flashes
8000
7000
6000
5000
4000
3000
2000
1000
0
1/1/1997
4/1/1997
7/1/1997
10/1/1997
1/1/1998
4/1/1998
7/1/1998
10/1/1998
1/1/1999
4/1/1999
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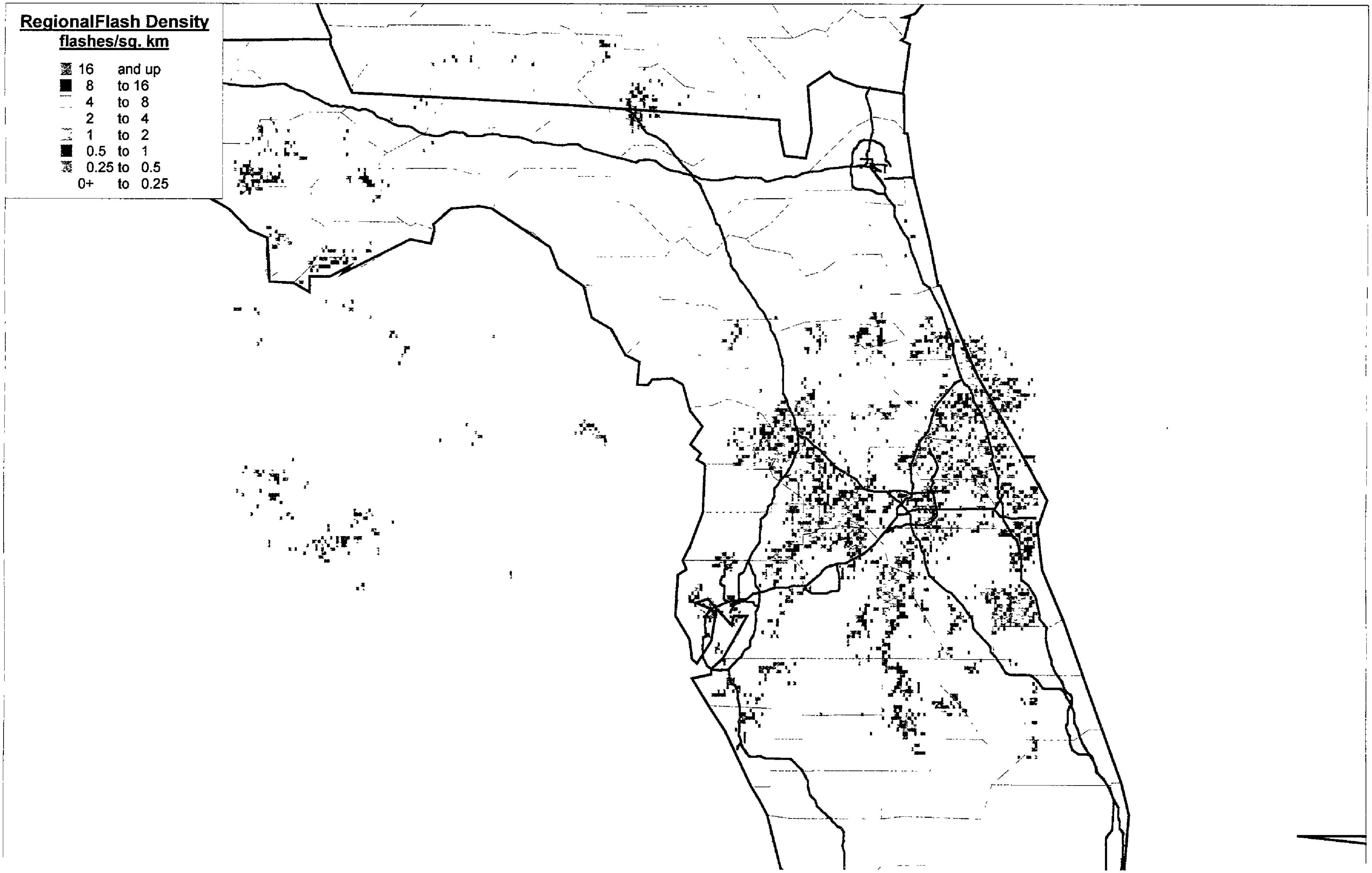
4/1/2003
7/1/2003
Date

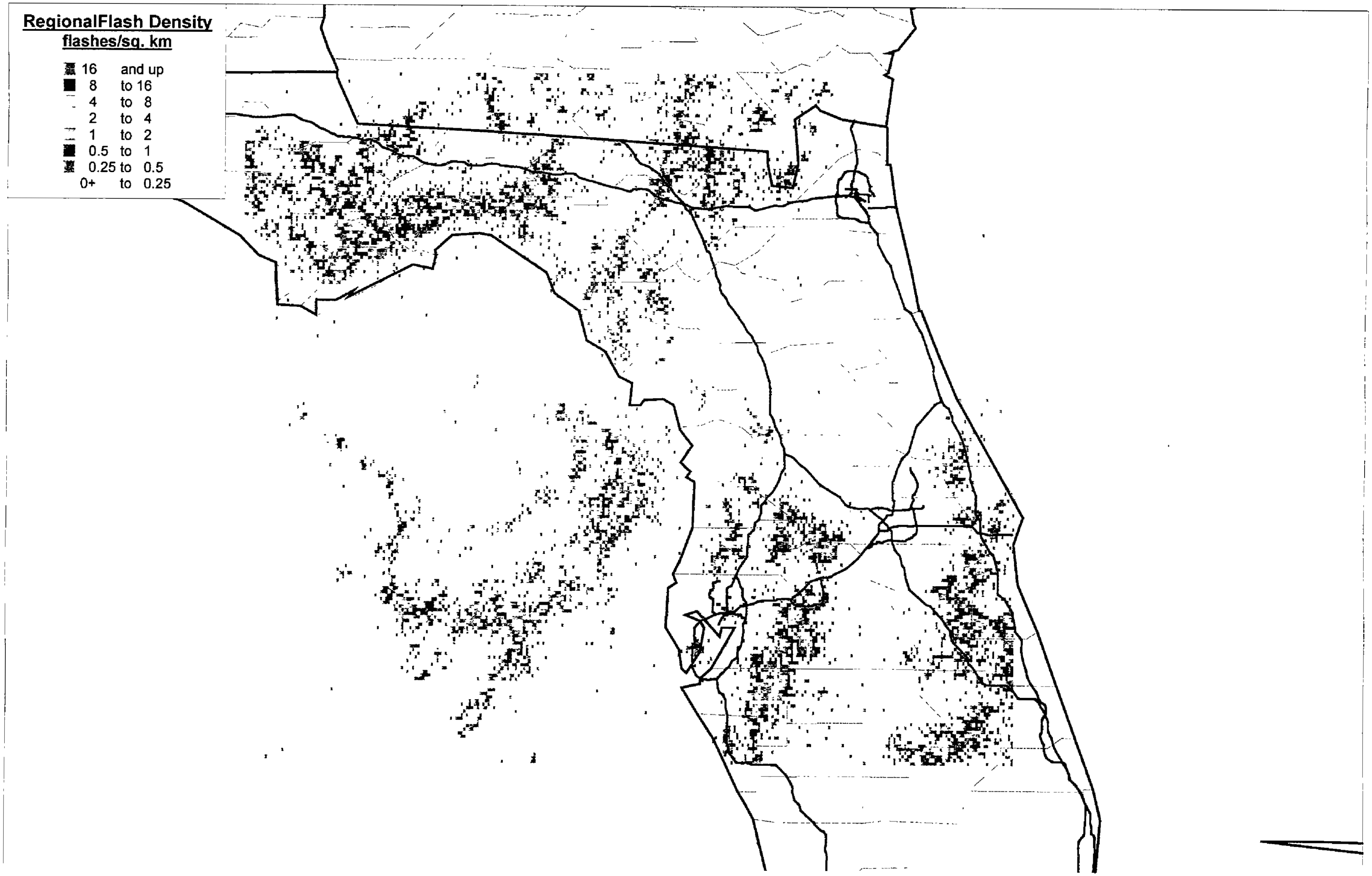
**EXHIBIT B**

# DAILY COMPOSITE RADAR FLASH DENSITY MAPS
# FOR JULY 15 THROUGH JULY 21, 2003

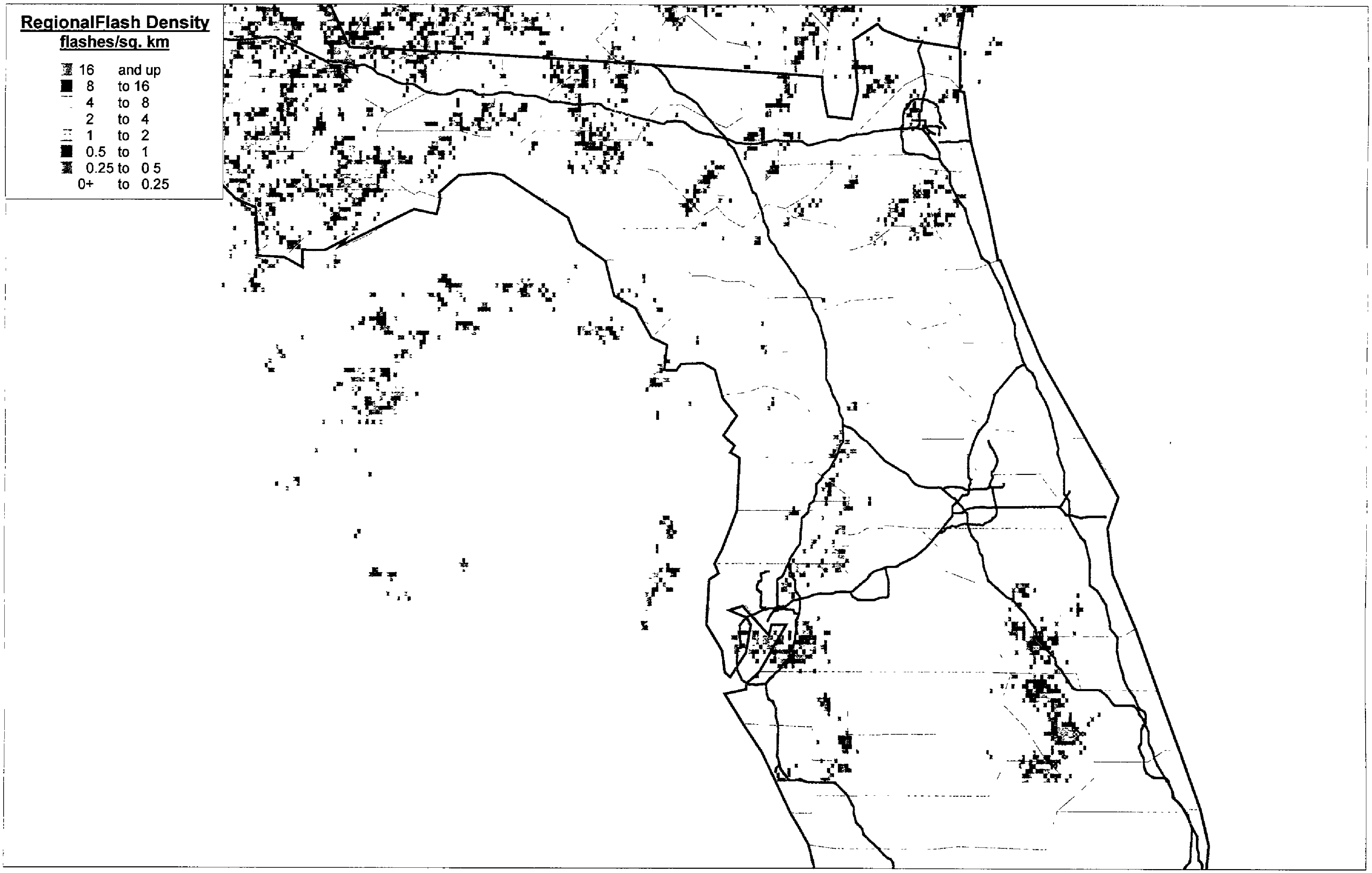
# 7/15/2003 Flash Density



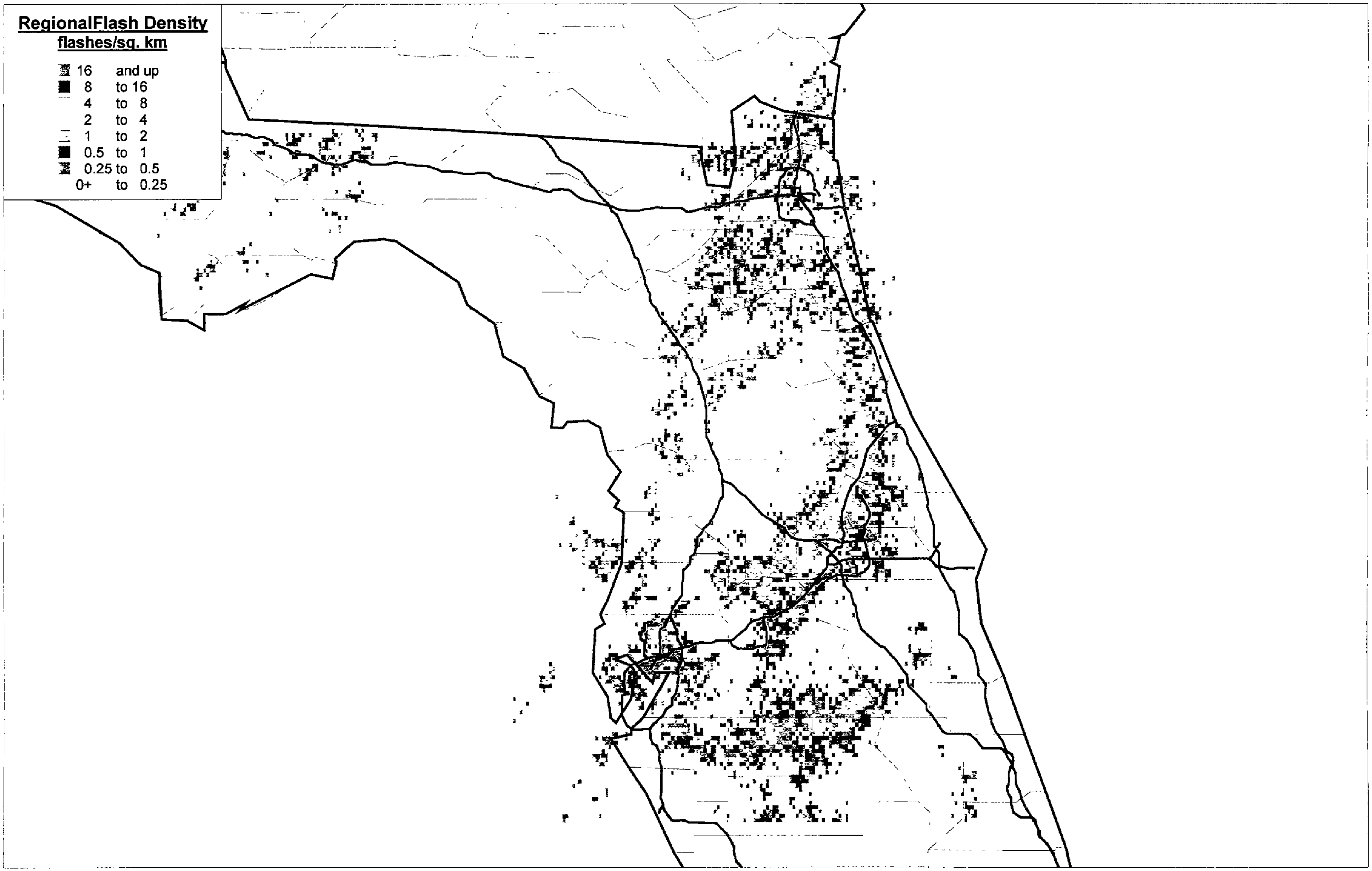
# Lightning Flash Density 7/16/03



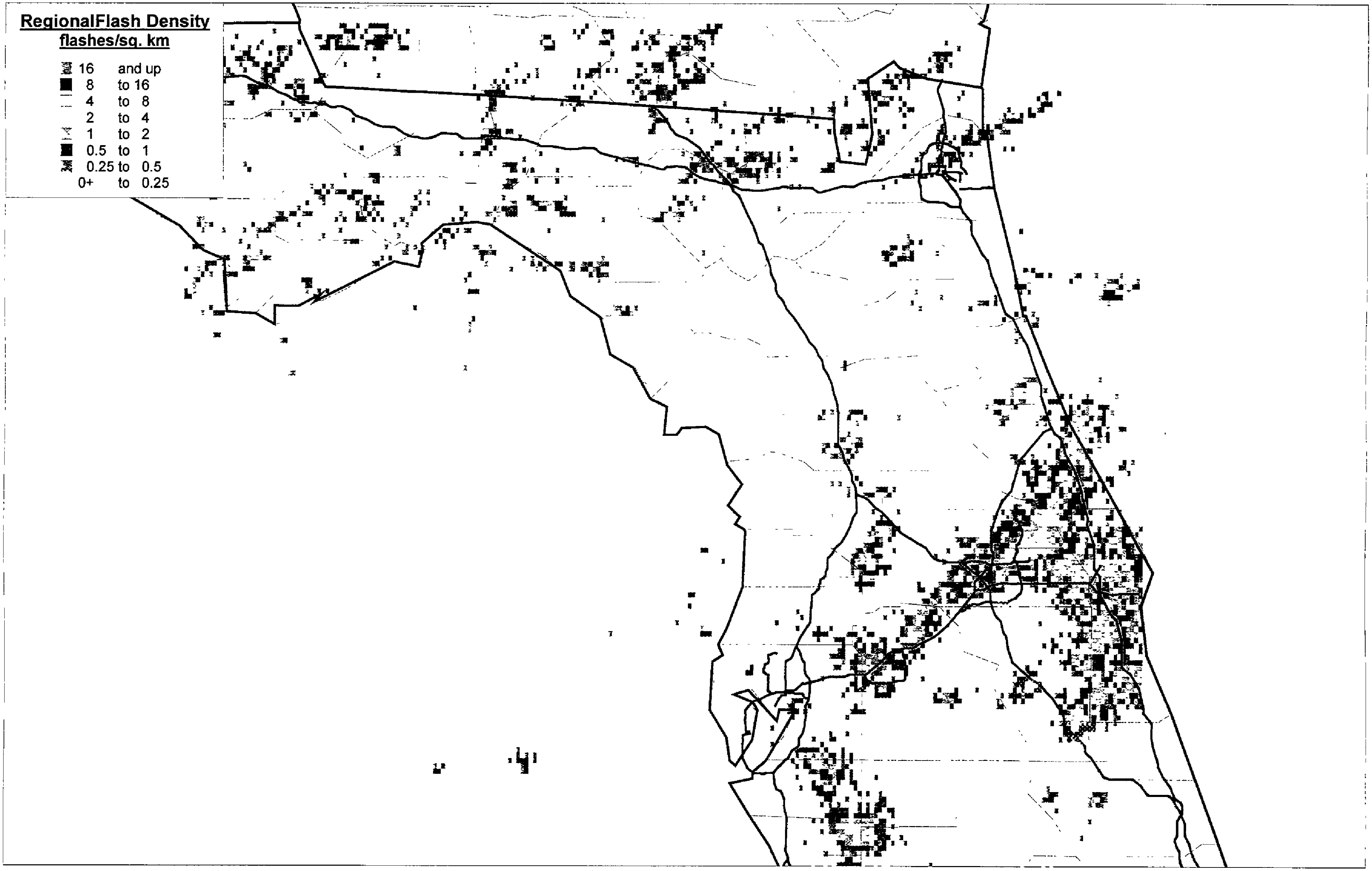
# 7/17 Lightning Flash Density



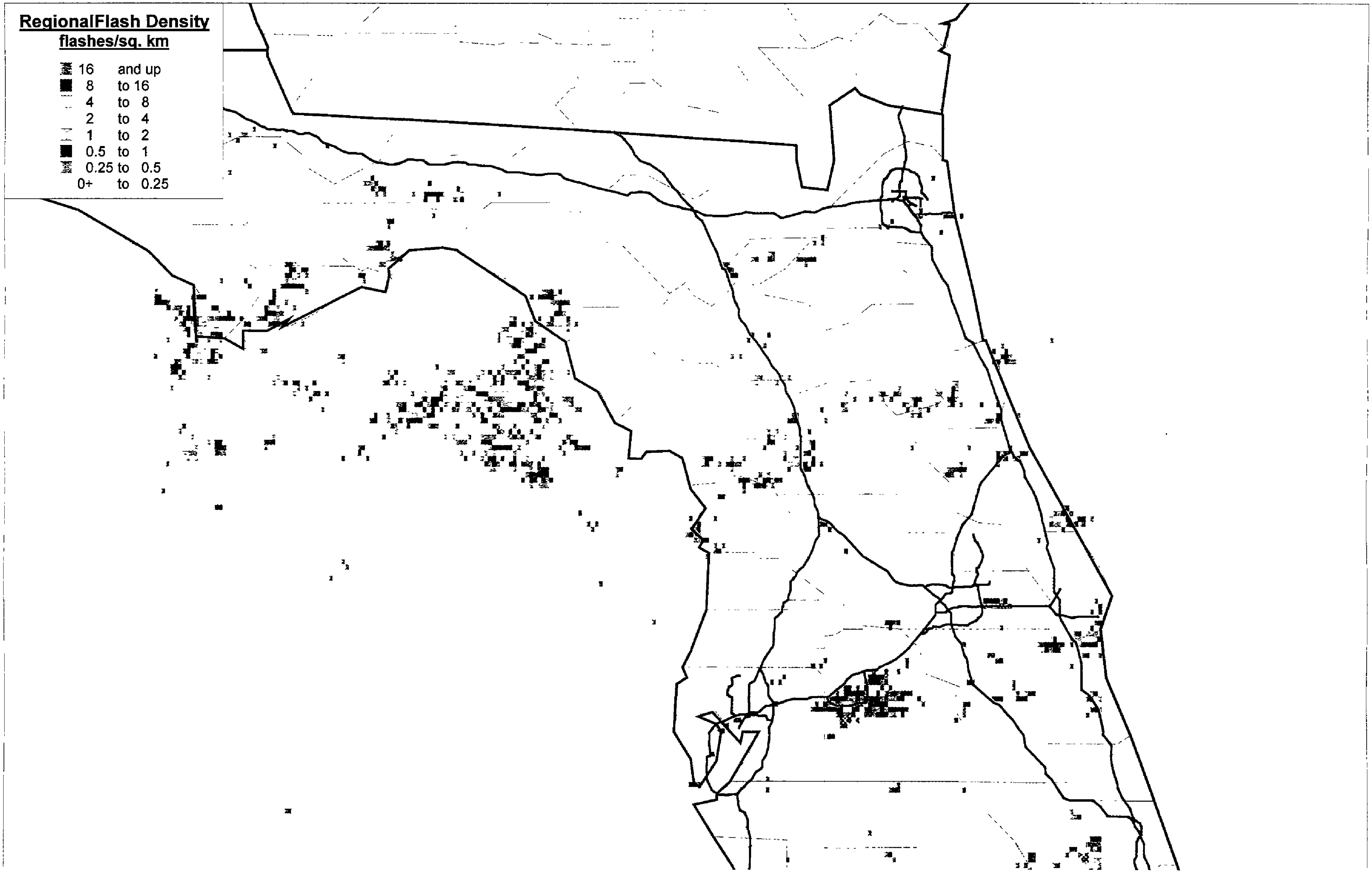
# 7/18/2003 Flash Density



# 7/19/2003 Flash Density



# 7/20/2003 Flash Density



# 7/21/2003 Flash Density

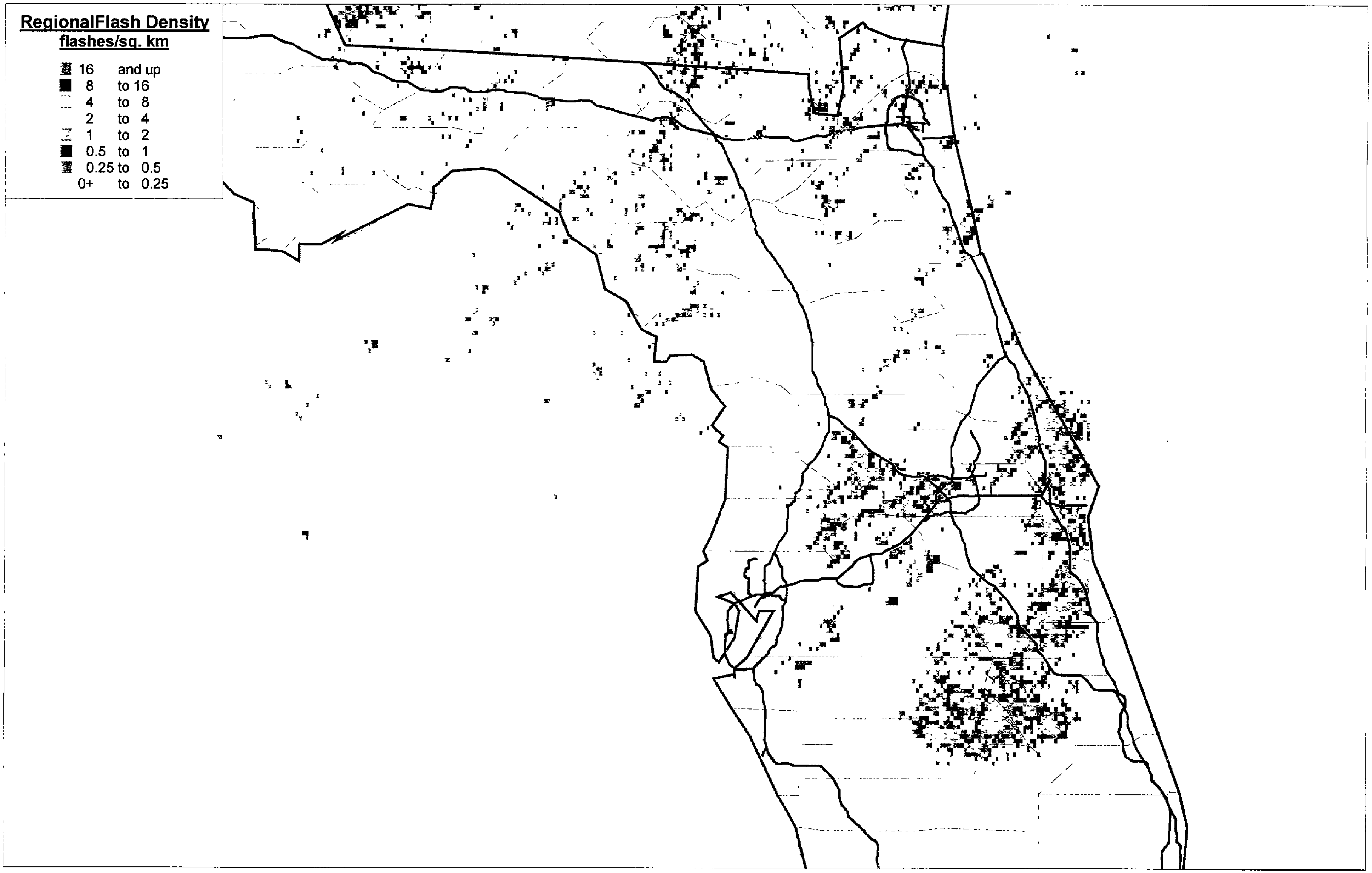


**EXHIBIT C**

# IEEE WHITE PAPER

*CLASSIFICATION OF MAJOR EVENT DAYS*

# Classification of Major Event Days

Prepared by: Cheryl A. Warren, James D. Bouford, Richard D. Christie, Dan Kowalewski, John McDaniel, Rodney Robinson, David J. Schepers, Joseph Viglietta, Charlie Williams,
*Senior Members, IEEE*
On behalf of the Working Group on System Design

**Abstract-- A paper that explores the basis, need, and benefit of classifying reliability performance relative to major events. Today, many internal and external goals are set based on reliability performance. Internal as well as external comparison is difficult to make due to variations in weather, collection methods, and a plethora of other variables. The Working Group on System Design has developed a statistics based methodology that classifies reliability data into normal and major event days. After classification, analysis can be performed on each data set using separate processes to arrive at sound business decisions and to make internal comparisons possible. This paper describes the newly developed methodology, the "Beta Method".**

**Index Terms— Distribution Reliability, Major Event Day, 2.5 Beta Methodology, lognormal statistical approach, Storms.**

## I. Introduction

Deregulation and re-regulation have led electric utility regulators and customers alike to scrutinize the electric power industry. Claims of improved service for less cost have been used to foster deregulation. Regulators have tried to ensure a continuation, and in some cases, an improvement in electric service reliability under the new operating environment. Electric utility executives have endeavored to continue to maintain service levels without increasing cost, and in some cases, by decreasing expenditures. As a result both internal and external goals have been set around reliability performance, yet there has been no uniform methodology for removing events that are so far away from normal performance that they are known as outliers. Without removal of such events, the variation in annual performance is too great to set meaningful targets. This paper discusses the need to classify reliability performance. Normalizing reliability data will reduce the variability, thus making trending/goal setting possible. It will also segment performance during large-scale events so that appropriate post analysis can be performed.

Distribution re-regulation has been sweeping the country as evidenced[1] by Figure 1.

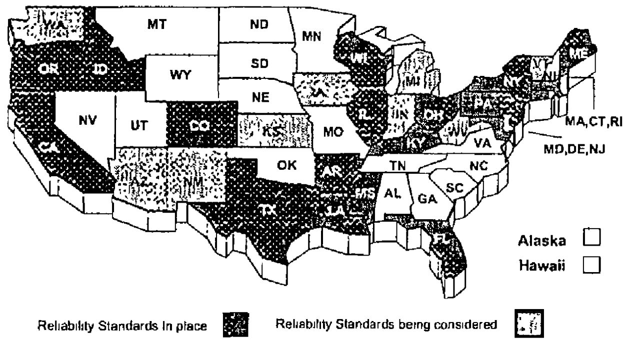



*Figure 1. US States involved with distribution reliability regulation.*

A few short years ago, only a hand full of states had formal distribution reliability reporting requirements. Today, the number has grown to over half of all US states and is continuing to rise. Some regulators have initiated extensive reporting requirements. Many regulators review not only annual statistics, but also lists of worst performing circuits, reliability expenditures and a variety of other detailed data items. Some states have extended regulatory boundaries to require utilities to purchase outage management systems ("OMS"). It is clear, that executives and regulators alike require a reasonable method for tracking and reporting reliability performance, a method that provides information for proper decision-making.

The IEEE Working Group on System Design, the group that authored the *Full-Use Guide on Electric Power Distribution Reliability Indices-1366-2001*, has recently developed a statistics based methodology (herein referred to as the "Beta Method") for identifying outlying performance (otherwise known as Major Event Days or MEDs). The method is known as the "Beta Method" because of its use of the naturally occurring log normal distribution that best describes reliability performance data, where Beta is a key parameter. Using the Beta Method, utilities can calculate indices on both a normalized and unadjusted basis (identifies abnormal performance). Appropriate decision-making can be performed on each set of indices. Normalized indices provide metrics that can, and should, be used for both internal and external goal setting. Unadjusted indices, when compared to the normalized indices, provide information about utility performance during major events. The Beta method identifies the occurrence of abnormal

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This paper was produced by the Working Group on System Design. Please see the last section of the paper for group membership.

[1] *"Reliability on the Regulatory Horizon"* by Cheryl A Warren and Michael J. Adams, Presented by Charlie Williams at the IEEE T&D Conference in Atlanta 2001

conditions that grossly affect the reliability of a system and using it allows the investigation of utility performance during major events. Events that may be included in unadjusted information are major weather events, major substation events, or unexpected catastrophic events such as earthquakes. Major events are events that are beyond the design and/or operational limits of a utility. It is anticipated that both executives and regulators will scrutinize those events that cause MEDs and take appropriate action to mitigate their future impact on reliability. There could be cases where no additional action is required, as would be the case when an event was beyond control and beyond the design and/or operation limits of the utility (e.g., Class 4 hurricane).

## II. Methodology Development

The Working Group is comprised of over 100 active members from thirty-one states and six countries that hail from universities, utilities, regulatory agencies and consultancies. The Working Group has spent the last two years creating a methodology that would:

- Be fair to all utilities regardless of size,
- Allow segmentation of reliability data into normal and abnormal categories, based on the identification of outlier events that cause Major Event Days,
- Allow use of normalized indices for internal and external goal setting,
- Be consistent for various amounts of data availability and for all utilities, and
- Be easy to understand and execute.

Many working group members anonymously provided their outage data for methodology development. A contingent of volunteer members from the working group performed rigorous analysis on all provided data while evaluating the efficacy of a number of proposed methods. Before the final methodology was chosen, several other methods were developed and abandoned due to their inability to meet the criteria noted above. Rich Christie authored "*Statistical Classification of Major Reliability Event Days in Distribution Systems*", a paper that describes some of the thinking. The working group has selected the Beta Method as the method best meeting the above criteria.

## III. The Beta Method

The method is easily applied to reliability data and can be set up to run automatically from an OMS, or be manually applied by using MS Excel™ and/or MS Access™. Its purpose is to allow major events to be studied separately from reliability performance that occurs during what would be considered normal operation, and, to better reveal trends in normal operation that would be hidden by the large statistical effect of major events.

The Beta Method is used to identify major event days. A major event day is a day in which daily SAIDI exceeds a threshold value $T_{MED}$.

In calculating daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption begins. This technique simplifies calculations and ties the customer-minutes of interruption to the instigating event.

The major event day identification threshold value $T_{MED}$ is calculated at the end of each reporting period for use during the next reporting period. For utilities that have six years of reliability data, the first five are used to determine $T_{MED}$ and that threshold is applied during the sixth year. The methodology follows:

1. Values of daily SAIDI for a number of sequential years, ending on the last day of the last complete reporting period, are collected. Consistency of future results is enhanced if five or six years of data are used, but, if fewer than five years of historical data are available, all of the available complete year, historical data should be used. Use of more than six years of data may distort the effects of major events and minimize the impact of the analysis.

2. Replace any day in the data set that has a value of zero for SAIDI with the lowest non-zero SAIDI value in the data set. (This permits the calculation of the logarithm of a SAIDI value for every day. While not technically precise, this does enhance the overall accuracy and consistency of the method.)

3. The natural logarithm (ln) of each daily SAIDI value in the data set is calculated.

4. The average of the logarithms, $\alpha$ (Alpha), (also known as the log-average) of the data set is calculated.

5. The standard deviation of the logarithms, $\beta$ (Beta), (also known as the log-standard deviation) of the data set is calculated.

6. The major event day threshold, $T_{MED}$, is calculated by using the equation:

$$T_{MED} = e^{(\alpha+2.5\beta)}$$

(Note that this value should in theory give, on average, 2.3 major event days per year. In practice, using the donated utility data, higher numbers of major event days per year, from two to eight, are seen. This is not unexpected since the actual data does not conform precisely to the log-normal distribution.)

7. Any day that occurs during the subsequent reporting period with daily SAIDI greater than the threshold value $T_{MED}$ is designated a major event day. The data for this day

should be removed when calculating normal reliability performance.

It is the group's recommendation that major event day performance be reviewed in a different, possibly more rigorous, manner than normal day performance.

SAIDI was chosen as the metric in order to capture the effects on customer minutes interrupted ("CMI") or duration of events. SAIDI is the division of CMI and total customers served. Dividing by total customers served allows utilities to use the methodology even after a merger has occurred. Despite the fact that SAIDI is used as the metric to determine MEDs, the methodology is applied to all indices.

Because the methodology classifies all performance into two data sets, 1) normal performance and 2) abnormal performance, it cannot favor a poorly performing utility. All data is provided in one of the two classifications. It is up to executive management and regulators to review both data sets to draw conclusions about overall performance.

## IV. Examples of the Methodology Results

For a detailed calculation example please refer to *Draft 9 of the Full-Use Guide on Electric Power Distribution Reliability Indices 1366-D9.* Using data provided by member utilities, two illustrative examples are presented here. Utility 4 used three years of data to determine threshold values while Utility 10 used seven years of data.

### *A. Example 1 - Utility 4*

Figure 2 and Figure 3 show analysis results from Utility 4. The lower light blue bars show the normalized values for SAIFI and CAIDI. Utility 4 is required to report SAIFI and CAIDI, not SAIDI to their regulator. The upper orange bars show the contribution from abnormal events to SAIFI and CAIDI. The summation of the two bars is the total system SAIFI and CAIDI or unadjusted SAIFI and CAIDI. Note that normalized SAIFI performance was constant, with no more than 3% variation from year to year. The normalized CAIDI was relatively constant, with no more than an 8% variation. Unadjusted, SAIFI varied 11% from year to year and CAIDI varied between 56% and 70% over the period.

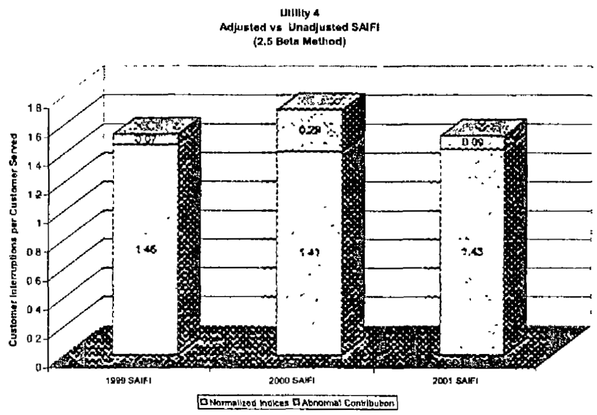


*Figure 2. Utility 4 SAIFI*

Figure 3 illustrates the significance of identifying abnormal events. In evaluating three years of provided data, it is evident that 2000 had the most major event activity. In this case major event days were caused by weather. For that year (2000), over 42% of the utility's overall CAIDI could be attributed to the abnormal event CAIDI. Notice that normalized CAIDI was fluctuating within a reasonable band (no more than 8% variation from year to year). It is likely that the system is performing within acceptable design and or operational limits. The fact that major event contributions vary from year-to-year is to be expected, and may be directly correlated to weather variations. If the major event variation is due to conditions within the utility's control, then executives and regulators should take appropriate action.. Furthermore, if over time there is indeed a true and sustained change in the weather patterns affecting a utility's service territory, this "normalization" process will reflect (and include) that change. If that occurs, then there are strong and supported reasons for the utility to change it operating practices.

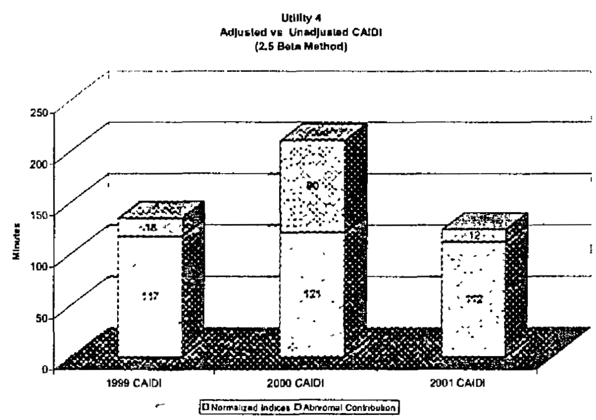


*Figure 3. Utility 4 CAIDI*

Figure 3 is a clear example of why normalizing indices is critical to customers, regulators and internal utility goals. If the unadjusted data were used to target spending, then this utility might be focused on the wrong issues (e.g., events that occurred as a result of one major storm and are unlikely to occur again in the foreseeable future).

*B. Example 2 - Utility 10*

Figure 4 and Figure 5 show results from Utility 10. SAIFI, even adjusted, is still increasing at a steep rate, while CAIDI is oscillating and is fairly constant. Given this type of information, executives from this utility may alter spending and action plans if no recent IT systems changes have been implemented that might account for the steep rate of SAIFI change. If this utility recently implemented a fully connected outage management system that more accurately captures reliability information, then these graphs could be explainable by that fact alone. It is well known that after fully connected IT systems are implemented, that reliability appears to worsen since more accurate information is being collected. For this example, we assume that no system changes occurred.

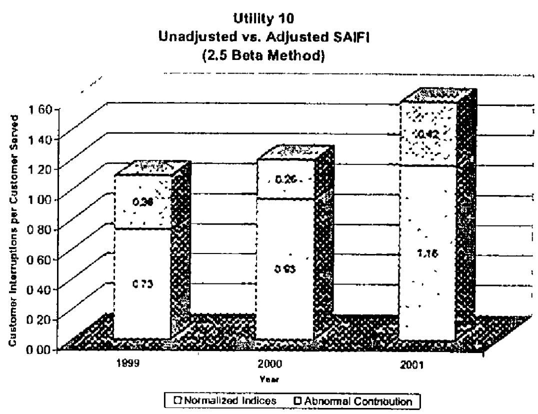


*Figure 4. Utility 10 SAIFI*

Figure 4 shows unadjusted CAIDI varies as much as 69% while adjusted CAIDI varies only as much as 28% a year for this utility. While 28% is a high percentage, it is significantly better than unadjusted statistics. This information may indicate crew overload on major event days. It appears that the major events were significant enough to completely saturate crew availability and thus restoration efforts were excessively delayed.

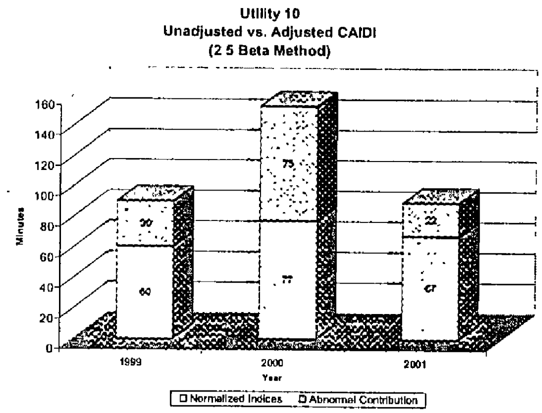


*Figure 5 Utility 10 CAIDI*

*C. Example 3 – Worst Performing Circuits*

Many state regulators are requesting reports on worst performing circuits ("WPC"). Typically, all interruption data is used to determine the WPC list. The number of circuits reported to regulators across the US varies from 4% to 10% of the total circuits on the system with each state allowing different reliability data adjustments. There are only a few states, at the present time that review circuit performance based on storm-adjusted or major event classified information. Consequently, utilities may be required to investigate solutions to problems that would only occur during a major event. This may not be the most cost-effective approach. The Beta Method will allow utilities to apply worst performing circuit criteria to adjusted data, thus identifying circuits that are most likely to remain worst performing if actions are not taken. In cases where WPC criteria is applied to all events, circuits often become members of this group due to one extreme event. Using non-classified data seems to defeat the regulatory purpose, which presumably is to solve repetitive reliability issues on problem circuits.

This paper has provided two simple examples using the Beta Methodology. During methodology development, many utilities used the beta method on their own data and determined it to be a fair methodology. It is important to remember that when using the 2.5 Beta Method, ***no data is excluded***, instead it is classified, analyzed and reported upon using separate processes.

## V. BENEFIT SUMMARY

Daily, decisions are made at utilities based on perceived risk versus anticipated reward. The Beta Method provides a mechanism to segment information into appropriate categories allowing different decision paths to occur. It is the hope of this group that classification will result in better business decision-making. Regulators, utilities, and customers benefit from the Beta Method because it segments reliability performance to reveal trends that utilities can then address.

A large group, with representation from all interested parties, created this methodology. The Beta Method allows utilities and regulators to confidently set goals/targets based on normal, and expected future performance. It also provides a technique to review performance during severe events.

## VI. Working Group Members

***Cheryl A. Warren* - Chair***
* Indicates participation on sub group that performed analysis and wrote text.

John Ainscough - Xcel Energy
Greg Ardrey - Alliant Energy
Ignacio Ares - Florida Power & Light Company
Gene Baker - Florida Power Corp. MT3B
John Banting - Cooper Power Systems
Jerry Batson - Alliant Energy
Steve Benoit - Minnesota Power
Lina Bertling - Royal Institute of Technology
Roy Billinton, D.Sc., P.Eng. - University of Saskatoon
Dave Blew - PSEG
Math Bollen - Chalmers University of Technology
**James D. Bouford - National Grid***
Richard Brown - ABB
Joe Buch - Madison Gas and Electric
James Burke - ABB
Ray Capra - Consultant
Mark Carr - AEP
Donald M. Chamberlin - Northeast Utilities
Jim Cheney - Arizona Public Service
Simon Cheng - Puget Power
Dave Chetwynd - BC Hydro
Ali Chowdhury - MidAmerican Energy
**Richard D. Christie, Ph. D. - University of Washington***
Rob Christman - FPL
Larry Conrad - Cinergy Corp
Ed Cortez - Stoner Associates Inc.
Grace Couret - Florida Power & Light Company
Tim Croushore - Allegheny Power System
Peter Daly - Power System Engineering
Rich D'Aquanni - Applied Resources Group Inc.
Bill Day - Distribution Management Consultants
Al Dirnberger - TXU
R. Clay Doyle - El Paso Electric
Russ Ehrlich - Conectiv
Charlie Fiajnvandratt - Navigant Consulting, Inc.
Doug Fitchett – American Electric Power
Robert Fletcher - Snohomish County PUD
Mahmud Fotuhi-Firuzabad - University of Saskatoon
Keith Frost – Exelon – Commonwealth Edison
Chris Gedemer – Advantica Stoner
Peter Gelineau – Canadian Electricity Association
David Gilmer – Yampa Valley Electric Association
Jeff Goh – PG&E
Manuel Gonzalez – Reliant Energy
John Grainger – University of North Carolina
Don Hall – CES International
Mark Halpin – Mississippi State University
Dennis Hansen – PacifiCorp
Randy Harlas – El Paso Electric Company
Mostafa Hassani – PEPCO
Harry Hayes – Ameren
Charles Heising – Alaska Power & Telephone Company
Eric Helt – Exelon – PECO Energy
Richard Hensel - Consumers Energy Company
Jim Hettrick - MidAmerican Energy
Francis Hirakami - Hawaiian Electric Company
Dennis B. Horman - Utah Power & Light Co.
George E. Hudson - Virginia Power
Brent Hughes - BC Hydro
Joseph Hughes - Electric Power Research Institute
Carol Jaeger - Puget Power
Kevin Jones - Advantica Stoner
Karim Karoui - Tractebel
Mark Kempker - AES - IPALCO
John Kennedy - GA Power Company
Tom Key - EPRI-PEAC
Mladen Kezunovic - Texas A&M University
Mort Khodaie - Public Service CO NM
Margaret Kirk - Peninsula Light Co
Don Koval - Universiy of Alberta
**Dan Kowalewski – Exelon - Commonwealth Edison***
David Kreiss - Kreiss Johnson
Thomas M. Kulas – Xcel Energy
Frank Lambert - Georgia Tech/NEETRAC
Larry Larson - Otter Tail Power Co
Ken Lau - PG&E
Jim Laurich - FirstEnergy Corp.
Robert E. Lee - Pennsylvania Power & Light Co.
Jim Lemke - Cinergy
Gene Lindholm - AES/CILCO
Raymond M. Litwin - Northeast Utilities
Vito Longo - Power Technology Consultants LLC
Andrea Mansoldo - Pirelli Cavi e Sistemi S.p.A
Arshad Mansoor - EPRI-PEAC Corporation
Mike Marz - Cooper Power Systems
**John McDaniel - Detroit Edison Co.***
Stephen Middlekauff - CP&L
Bill Montgomery - Con Edison
J.C. Montgomery - Detroit Edison Co.
Chris R. Mueller - RTE Zellweger
Jerry Murray - Oregon PUC
Peter Nedwick - Dominion - Virginia Power
Gregory Olson - Public Service Electric & Gas
Anil Pahwa - Kansas State University
Dan Pearson - PGE
Theodore Pejman - USDA-RUS
Christian Perreault - Hydro Quebec

Charles Perry - EPRI - PEAC
Robert Pettigrew - Beckwith Electric Company
C.Y. Pi - Moore Systems
Steven L. Puruckner - ORNL
Steve Quade - Northern States Power Company
Gary Rackliffe - ABB/Automated Distribution
Ignacio Ramirez-Rosado - University of La Rioja
Wanda Reader – Exelon –Commonwealth Edison
John Redmon - John R Redmon, Inc.
Sebastian Rios - Catholic University Chile
**Rodney Robinson - Westar Energy***
Fred A. Rushden - Rushden Consulting & Research
David Russo - Seattle City Light
Dan Sabin - Electrotek Concepts
Shafi Sabir - Scarborough PUC
Jim Sagen - Fort Collins Light & Power Dept.
Bob Saint - NRECA
Joe Santuk - Dominion - Virginia Power
**David J. Schepers – Ameren***
Ken Sedziol - Cinergy
Peter Shaw - Consultant
Michael Sheehan - Puget Sound Energy
Tom Short - EPRI-PEAC
Hari Singh - Cooper Power Systems
John Spare - KEMA Consulting
John Sperr - Rochester Instrument Systems
Lee Taylor - Duke Power Co.
Rao Thallam - Salt River Project, ISB 240
Ridley Thrash - Southwire Company
Betty Tobin - Seattle City Light
Hahn Tram - SchlumbergerSema
Hector Valtierra – Exelon - Commonwealth Edison
S.S. (Mani) Venkata – Iowa State University
**Joseph Viglietta –Exelon PECO Energy Company***
Marek Waclawiak - United Illuminating Co.
Daniel J. Ward - Dominion - Virginia Power
Carl Warn - Rochester Gas & Electric Corp.
Neil Weisenfeld - Con Edison
Greg Welch - ABB Power T&D Company, Inc.
Lee Welch - Georgia Power Company
Val Werner - Wisconsin Electric
**Charlie Williams - Florida Power - A Progress Energy Company***
Bill Winnerling - EPRI
Mike Worden - NY PSC