ILLINOIS POWER

Annual Report for the 2000 Reporting Period
Pursuant to 83 Illinois Administrative Code 411

June 1, 2001

Revised June 25, 2001

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Introduction

Pursuant to Section 411.120 of Illinois Administrative Code Part 411 (“Part 411”), Illinois Power Company (“Illinois Power”, “IP” or the “Company”) submits this annual report pertaining to the reliability of the Company’s electric transmission and distribution (“T&D”) system. This report covers the twelve-month period ended December 31, 2000.

The report reflects a significant deviation from the format and level of detail presented in prior annual reliability reports. The Company’s objective for this report was to make it easier to read and more concise in terms of IP’s commitment and plans to construct, operate and maintain a safe, reliable, and cost effective energy delivery system.

IP’s Commitment

Electric distribution service reliability is one of the top priorities for IP and its parent company, Dynegy, Inc. (“Dynegy”). IP is committed to demonstrating leadership in reliability through performance as a model energy delivery company. Further, Dynegy recognizes that a reliable energy delivery system is critical to the success of Illinois Power.

IP is committed to working with the Illinois Commerce Commission (“ICC” or the “Commission”) on initiatives to ensure the reliability of the delivery system. IP believes this has been demonstrated through the Company’s complete and thorough response to ICC Staff’s (“Staff”) data request in Docket No. 00-0310, meetings held at the ICC to update both Staff and Commissioners on IP’s progress on reliability initiatives, IP’s willingness to work with Staff and other utilities to more fully understand fundamental differences between Illinois utilities and ongoing efforts to develop a comparable methodology that Staff can use to measure all utilities, and through the Illinois Energy Association (“IEA”) meetings. While acknowledging these efforts may lead to alternate reliability measures, IP encourages the ICC to give the existing reliability measures in Part 411 an opportunity to achieve the intent of the original rule.

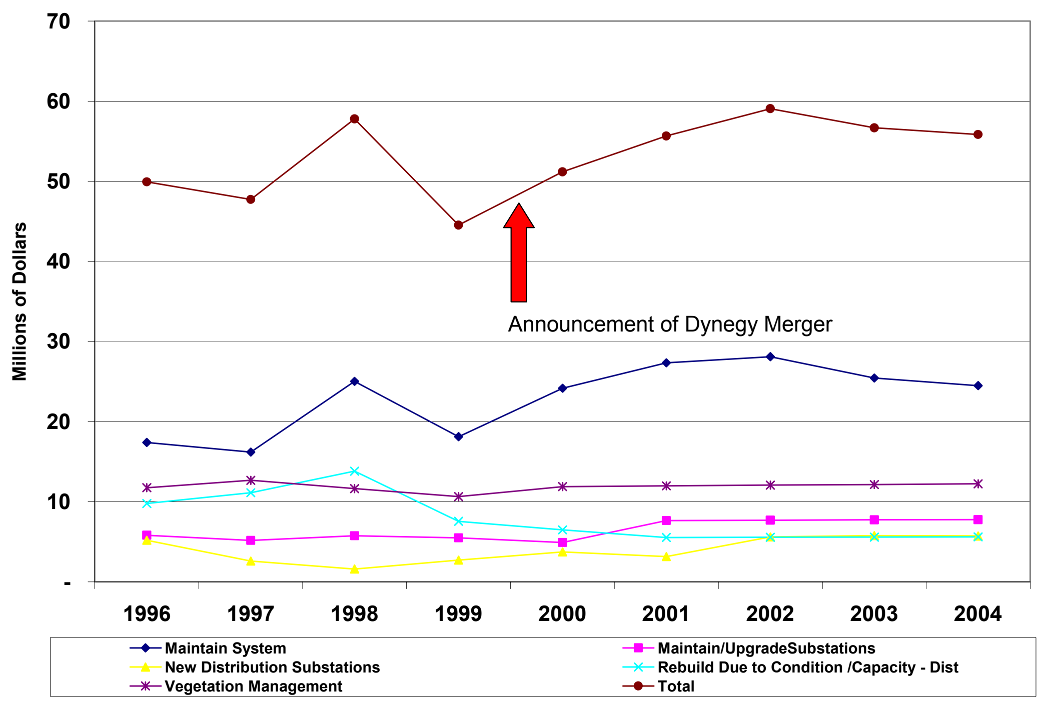
No electric distribution system can be 100 percent free from interruption. To achieve even a “near perfect” system would be cost prohibitive. Therefore, IP’s goal is to determine and implement the appropriate policies, procedures, practices, processes, and programs necessary to provide a level of reliable service that meets its customer’s requirements in a cost effective manner.

IP personnel work around the clock, in all weather, to ensure that reliable service is provided. The Company continues to expand and enhance its existing system infrastructure to meet the constantly changing demands of its customers. Significant resources have also been expended for state-of-the-art information systems to assist Company personnel in identifying, tracking, analyzing and responding to service interruptions more efficiently and effectively. IP recognizes that more can be done and will continue to use technology to improve the reliability of its delivery system.

To reinforce the Company's commitment, during calendar year 2001, IP will establish reliability related goals for all employees within the Energy Delivery Department. All employees from the senior management to individual linemen will have measurable goals designed to provide the necessary focus on reliability improvement. These goals will be in place by year-end with performance against these goals tracked beginning in 2002.

There are key elements to IP's reliability program. These elements include system planning; design/build processes, procedures, standards, and guidelines; effective use of supporting technology; maintenance and repair activities; service restoration; and reliability index performance. Employee's goals will be structured to reflect these key elements. While the Company adheres to its commitment to provide reliable service, business realities mandate that funds be prioritized, committed, and expended in accordance with constraints established by customers, regulators, the financial community and Company management.

The Company continues to make substantial investments in its T&D system. As shown by Figure 1, the Company's expenditures on reliability-related initiatives (both capital and O&M) are expected to remain at an appropriate level. The Company has implemented an Asset Management ("AM") process by which capital additions are more rigorously scrutinized to achieve the greatest enhancement to the distribution system.



• Figure 1. T&D Reliability Expenditures

The Company also employs a methodology to identify and prioritize projects designed to achieve cost-effective improvements in reliability. This methodology was created to assist IP with its response to the ICC filed on October 26, 2000 in Docket No. 00-0310. It allows IP to prioritize work on a ***zone of protection*** (discussed on page 15) and programmatic basis. After expenditure levels are established, work can then be organized and completed through efficient resource management on an area-by-area basis. The Company has further committed to upgrading its information technology ("IT") systems to automatically generate optimized reliability projects.

Additional activities have been initiated since the Company's last annual reliability report that are designed to enhance IP's focus on reliability-related issues. In summary, those activities are:

- Formation of a Centralized Reliability Group
- Enhancement of IP's Circuit Patrol
- Enhancement of Vegetation Management Activities
- Improvement of After Hours Response
- Mobilization of Crews for Anticipated Severe Weather Events
- Creation of an Operations Compliance Organization

During 2000, the Company formed a centralized reliability group as part of the Energy Delivery department to focus on identification of reliability issues and to ensure that efforts are appropriately prioritized and addressed. This group is also responsible for the development of specific reliability goals for each level of the Energy Delivery department. This group is also developing and providing line management with the necessary reports and information to accurately assess reliability performance. The group is also responsible for assisting field personnel with identification of reliability projects on both worst performing circuits and across the reliability landscape.

With regards to system maintenance, the Company has revamped its approach to patrolling circuits. Historically, the patrols were primarily focused on identifying and correcting safety-related issues. The program has been enhanced to include a thorough inspection and evaluation of each circuit every four years. Initial field training has been held with additional in-depth sessions being conducted prior to December 2001. The patrols provide valuable information on issues such as animal protection, lightning arresters, grounding, asset condition, and vegetation. Findings from these patrols are reported to area management and necessary maintenance work is prioritized, scheduled, and tracked through to completion. In conjunction with the Operations Compliance group (described below), the Energy Delivery department will track findings from circuit patrols in the electric compliance system ("ECS").

The Company has continued to enhance its vegetation management program, and IP is on track to achieve a four-year circuit-trimming schedule by the end of 2002. In 1999, the Company changed contractors resulting in greater efficiencies. This change, along with IP's tree trimming practices, has resulted in significantly more trees being trimmed annually. The Company also conducts aerial patrols of transmission lines in the spring and summer to ensure appropriate vegetation clearance of each year.

The Company has also taken a number of steps to expedite service restoration and improve communications with customers. The Company is continuing to emphasize meeting estimated restoration time ("ERT") goals. Instead of using computer generated restoration estimates, dispatchers contact field crews to provide customers with more accurate estimated restoration times. The Company has also initiated a proactive process by which crews are held-over at the end of a day if there is a high likelihood of storms affecting the Company's service territory. The Company is also working to improve after-hour response times. IP has portable substations and key system spares available that can be placed in service to either temporarily restore service or shorten extended periods of interruption. Each of these initiatives is designed to improve service restoration times for customers.

The Company has established an Operations Compliance group ("Compliance"). The group's objective is to ensure work is performed in accordance with existing programs, policies, procedures and processes. Feedback is provided to line management regarding areas that require additional attention. Compliance works closely with the Reliability group to ensure appropriate reliability improvement information is tracked by ECS.

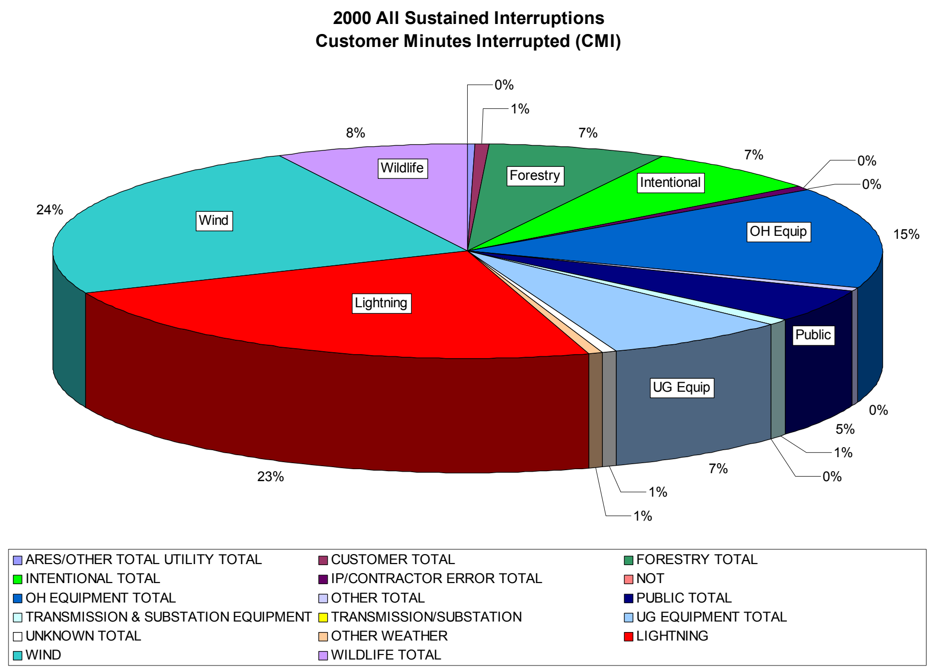
These initiatives will help to ensure appropriate activities are undertaken to maintain or improve existing levels of reliability.

IP's Reliability Indices

Employing Part 411 definitions outlined in section 411.20, in 2000, IP experienced a system SAIFI of 1.65 interruptions, a system CAIDI of 168 minutes, and a system CAIFI of 2.47 interruptions. Further discussion regarding IP's performance can be found in the section entitled "Comparative Data."

Interruption Data

In total, Illinois Power's customers experienced 23,031 sustained interruption events (i.e., events lasting more than one minute) resulting in 1,096,545 sustained customer interruptions ("CI") and 175,114,766 customer minutes of sustained interruption ("CMI"). The top causes of interruption based on customers interrupted, customer minutes interrupted and number of interruptions combined were wildlife, wind, lightning, and forestry. Figure 2 shows the CMI measurement component only. For this component, the top causes are wind, lightning, overhead equipment failure and wildlife.



• Figure 2. Summary of All Sustained Interruptions Reviewed by CMI by Cause

Based on this information, which is maintained in the Company's Trouble Outage System ("TOS"), IP has analyzed the interruption data and identified approaches for addressing persistent reliability issues. A summary of planned initiatives to address reliability issues is contained within this report.

IP's Information Technology Systems

TOS was created in 1992 and has evolved since that time to the state of the art system it is today. System and process enhancements include the ability: 1) to provide in-depth quality analysis, 2) to collect a snapshot of connected customers, 3) to record customer interruption history at the end of each year, 4) to accurately count interrupted customers by phase, and 5) to track step restoration. The Company's IT systems are unique because:

- Information collected in TOS can be overlaid on construction information collected in a distribution database ("DDB"), geographical information system ("GIS") circuit maps or any other IP system, enabling quick decision-making.

- IP is able to identify when one branch of its power system has had repeated problems and the cause of the problems. Using this data, IP personnel can quickly determine the best solution due to the connectivity of the models.

- IP tracks interruption data at the customer, phase, device, protective zone, and system levels.

The accuracy of the TOS and the fact that the system is modeled down to a customer level allows IP to address reliability mitigation to that customer level when necessary. Furthermore, IP has the ability to track on a zone of protection basis as described on page 16. By analyzing the interruption data at the appropriate level, IP can obtain the most reliability benefit for their expenditure.

It is widely recognized within the electric utility industry that utilities with very accurate IT systems, similar to IP's TOS system, have higher reliability indices than those utilities with less accurate systems. The major difference usually stems from inaccurate, inconsistent customer counts being recorded on historical, less accurate systems. When a protective device operates, a set number of customers reside beyond that device and are interrupted every time that device opens. Without connected IT systems, utilities often only estimate the number of customers interrupted. Connected systems provide an accurate count of the number of customers affected. Through various forums, such as Institute of Electronic and Electrical Engineers ("IEEE")/Edison Electric Institute ("EEI") meetings, utilities have reported experiencing an increase in reliability indices of approximately 25 percent after more accurate systems were placed in service. In a worst-case scenario, indices increased 75 percent. The change in indices was solely attributable to the change in systems. During system conversions, spending on reliability-related initiatives remained constant.

Comparative Data

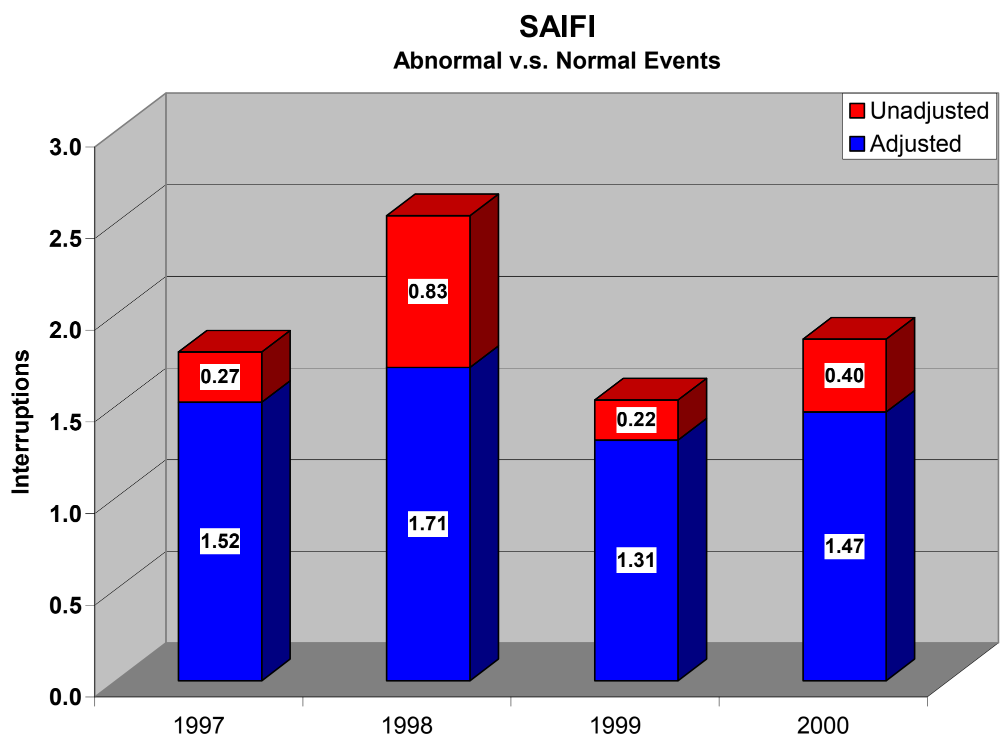
Year-to-year comparisons of one company's system to another are a popular vehicle by which to assess the relative performance. In today's environment, IP believes company-to-company comparisons provide limited meaningful insights. Differences between the nature of each company's service territory and the design and construction of its electric system negate the validity of these inter-company comparisons. Similarly, the sophistication of the information systems employed to identify, track and report interruption data affect the comparability of data. Finally, simple differences in definitional issues between companies can seriously compromise conclusions drawn based upon these comparisons.

IP believes the comparison of one company's year-to-year performance has proven to be a more accurate portrayal of a company's performance. The key to such a comparison is to ensure that uncontrollable variables have been identified and excluded prior to the analysis. Factors such as weather can significantly impact reliability indices from year to year. To develop a true comparison of the year-to-year performance of the company's system, uncontrollable variables such as weather should be excluded.

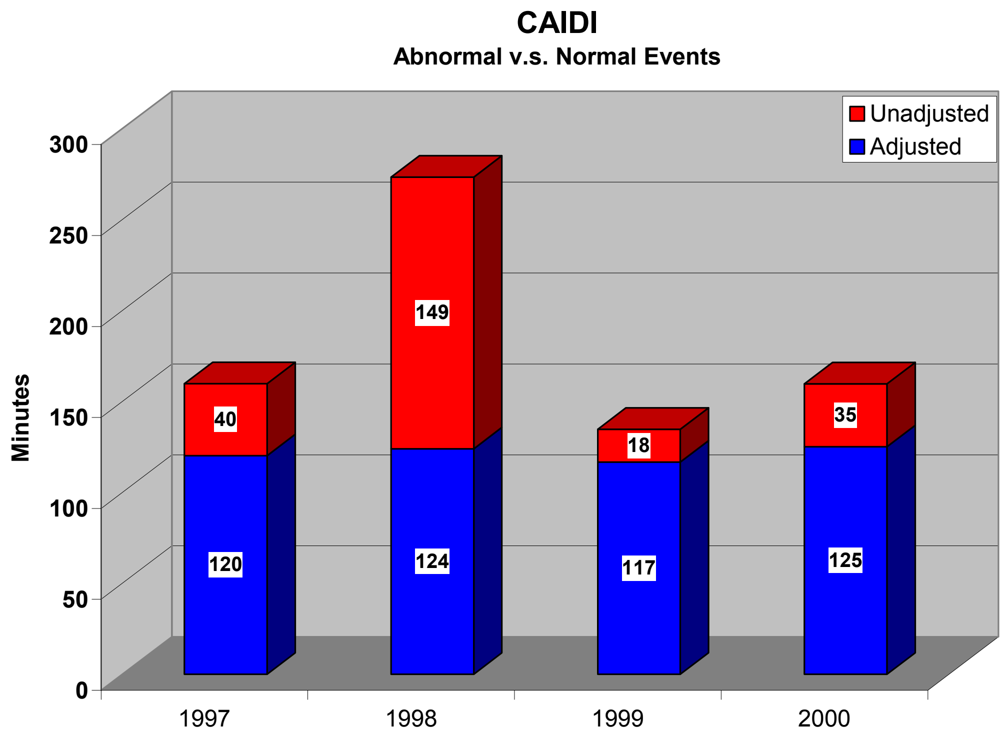
IP's electric distribution system performance, as reported including all variables, has experienced varying levels of reliability. Without excluding the impact of uncontrollable variables on these indices, flawed business and regulatory conclusions, and thus investment decisions, can be made. Monitoring normalized indices provides a more accurate indication of the Company's reliability performance over a period of time.

The IEEE has proposed an approach by which to classify all interruptions as either "normal" or "abnormal." This approach is currently under investigation by the IEEE Working Group on System Design as a way to compare utilities without specifically excluding weather. Abnormal events are defined as events that exceed normal operating conditions, which are defined by reviewing a utilities past performance. The concept is that utilities plot their events as shown in Figure 18 (on page 51)and Figure 19 (on page 51) to establish a base line for “normal”. “Normal” will be reviewed over time to ensure that system health is not degrading. The IEEE is proposing a plan that will encourage significant regulatory reporting for any event that exceeds “normal” and was under that utility’s control. One goal of this approach is to construct a methodology that ensures a clear picture of degrading system health. If the number of abnormal events rises significantly over time, then it will be clear that there are other systemic issues that require additional investigation.

After abnormal events are identified using the above described methodology, adjusted indices are compared to unadjusted indices. As can be seen in Figure 3 and Figure 4, IP’s reliability performance over time has been relatively constant considering “normal” events using this emerging IEEE methodology. The approach clearly shows the impact of abnormal events on system performance.



• Figure 3. SAIFI Performance Considering Abnormal Days



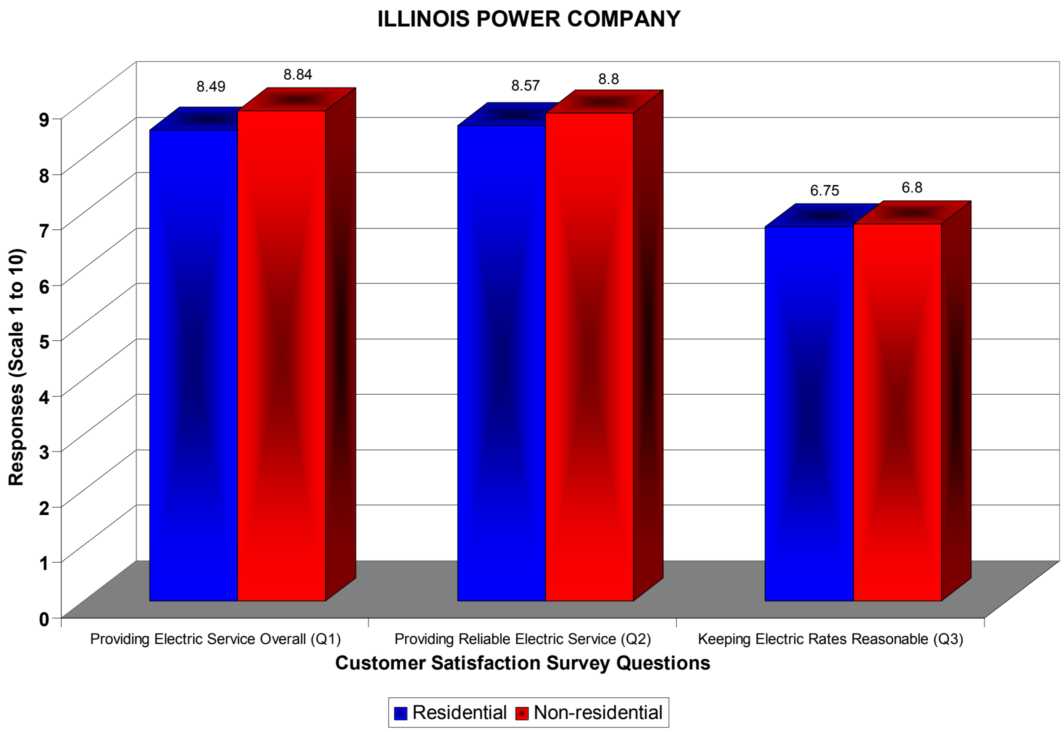
• Figure 4. CAIDI Performance Considering Abnormal Days

Identifying abnormal events also provides an opportunity for advanced CAIDI/restoration analysis during crisis situations. Segregating abnormal events and reviewing response times can provide insight on crew performance, supply locations, and trigger points for enlisting outside assistance.

Presuming that systems, definitions, and data collection techniques do not materially change over time, the information provided would offer more accurate insights into the performance of IP's distribution system than that available from unadjusted company-to-company comparisons.

Customer Satisfaction

The Opinion Dynamics Corporation ("ODC") conducted a survey of 600 residential and 400 non-residential customers addressing topics such as overall satisfaction and reliability performance of IP's distribution system. As shown in Figure 5, Illinois Power customers are satisfied with their electric service and reliability.



• Figure 5. Customer Satisfaction Survey Results

While customers were satisfied with overall performance and reliability, the survey did identify areas in which IP needs to further investigate. Based upon the results of the survey, IP must continue to provide reliable service without dramatically impacting rates.

Format of Report

The remainder of the report has been structured to respond to each section in Part 411. The text of Part 411 is provided in italics. The Company's response to each section, if applicable, is contained directly below the quoted section of the code.

Summary

Illinois Power and its parent company, Dynegy, are very serious about reliability and are taking prudent, cost-justified measures to ensure the continued offering of reliable, safe, and responsive service to all customers. Based upon IP's "normal" performance over time, the Company can demonstrate consistent performance in terms of providing reliable service.

The Company has attempted to address within this report many of the issues that arose subsequent to the filing of last year's. Over the last few years the Commission has intensified its focus on energy delivery reliability. Such activities do not come without cost to the Company and its customers. While responding to frequent and voluminous requests for information consumes significant IP resources that could otherwise be used to address reliability-related issues, the Company has and will continue to work with Commission Staff to define, analyze and summarize reliability data in a meaningful manner.

Section 411.20 Definitions

This section of the Rule sets forth definitions to be used for this filing. Some definitions have required interpretation and this section will outline IP's interpretation of the definitions.

All index calculations started from a database of sustained electric interruptions (those lasting more than one minute).

Worst Performing Circuits

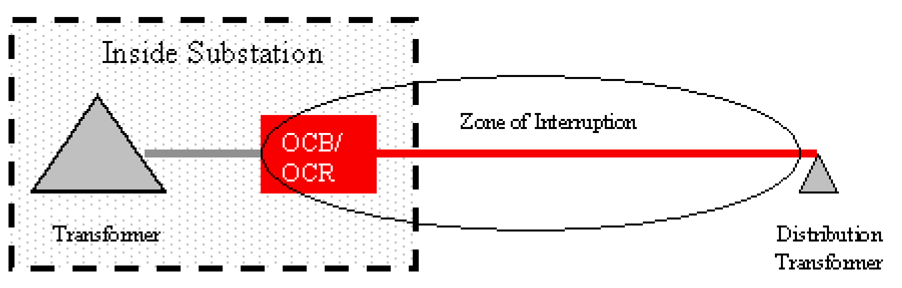
The worst performing circuits (WPC) definition relies on two other definitions from Part 411.20 as detailed below:

"Worst-performing circuits" are those distribution circuits that, for each reliability index, are among the one percent of all circuits in an operating area (or at least one circuit for each reliability index) with the highest achieved values (lowest performance levels) for the reliability index. For the purpose of identifying worst-performing circuits, only distribution circuit interruptions and customers affected by such interruptions shall be considered in calculating the reliability indices.

"Distribution circuit" is a circuit owned and/or operated by a jurisdictional entity and designed to operate at a nominal voltage of 15,000 volts or less and to supply one or more distribution transformers.

"Distribution circuit interruption" is an interruption originating at a point that is between the circuit-interrupting device at the substation supplying the distribution circuit and the distribution transformer.

Based on these three definitions, IP has calculated worst performing circuit indices for the 899 circuits that serve customers at 15 kV or less. IP further included only interruptions that occurred between the substation breaker/recloser and the distribution transformer as shown in Figure 6.



• Figure 6. Distribution Circuit for WPC Calculations

IP further excluded interruptions with the following cause codes per the "Interruption" or "Outage" definition: transmission and substation, ARES or Other utility or ISO caused, Customer Totals, and Intentional. The specific excluded cause codes are:

• Table 1. Worst Performing Circuit Cause Code Exclusions

Category	Cause Description	Cause Code
ARES/OTHER TOTAL UTILITY TOTAL	LOSS OF SUPPLY	LOSS
ARES/OTHER TOTAL UTILITY TOTAL	OPERATING EVENT	OAEV
ARES/OTHER TOTAL UTILITY TOTAL	LOSS OF SUPPLY	OASS
ARES/OTHER TOTAL UTILITY TOTAL	OPERATING EVENT	OPEV
CUSTOMER TOTAL	CUSTOMER EQUIPMENT	CUCE
CUSTOMER TOTAL	CUSTOMER REQUEST	CUCR
CUSTOMER TOTAL	NONPAYMENT OF BILL	CUNP
CUSTOMER TOTAL	TAMPERING WITH SERVICE	CUTS
INTENTIONAL TOTAL	EMERGENCY REPAIRS	SCER
INTENTIONAL TOTAL	POLICE/FIRE/GOVT. AGENCY	SCGA
INTENTIONAL TOTAL	UNSAFE/HAZARDOUS CONDITIONS	SCHC
INTENTIONAL TOTAL	PROTECTION SYSTEM INTEGRITY	SCLC
INTENTIONAL TOTAL	MAINTENANCE/REPAIR/UPGRADE	SCMU
INTENTIONAL TOTAL	SCHEDULED CONSTRUCTION	SCSC
NOT	NON-IP PROBLEM	OTNI
TRANSMISSION & SUBSTATION EQUIPMENT	SUBSTATION EQUIPMENT	TSSE
TRANSMISSION & SUBSTATION EQUIPMENT	TRANSMISSION SYSTEM OUTAGE	TSTS
CUSTOMER	ACCESS TO EQUIPMENT DENIED	CUAD
CUSTOMER	INTERRUPTIBLE SERVICE TARIFF	CUIS

ICC Indices

Calculation of the ICC reliability indices required a different definition and hence a different data slice. For the ICC reliability indices, calculations were made for all circuits (1239) regardless of voltage. Transmission and substation events were included, and all interruptions from the customer attributable to the transmission system were included. IP excluded interruptions with the following cause codes per the “Interruption” or “Outage” definition: transmission and substation, ARES or Other utility or ISO caused, Customer Totals, and Intentional. The specific excluded cause codes are shown in Table 2.

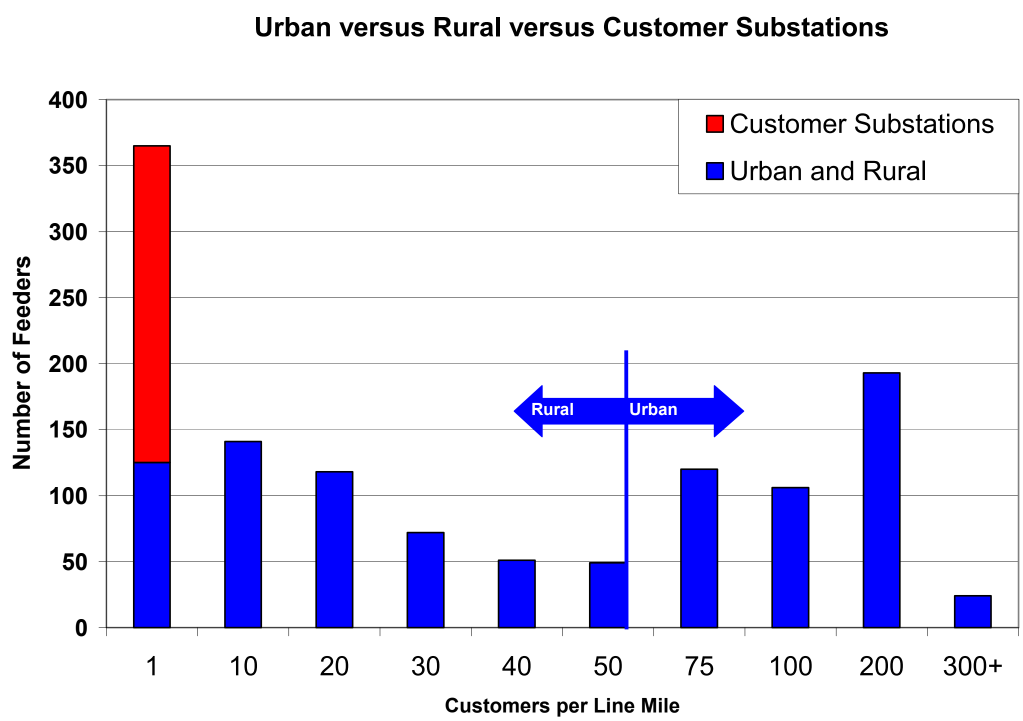
• Table 2. ICC Cause Code Exclusions

Category	Cause Description	Cause Code
ARES/OTHER TOTAL UTILITY TOTAL	LOSS OF SUPPLY	LOSS
ARES/OTHER TOTAL UTILITY TOTAL	OPERATING EVENT	OAEV
ARES/OTHER TOTAL UTILITY TOTAL	LOSS OF SUPPLY	OASS
ARES/OTHER TOTAL UTILITY TOTAL	OPERATING EVENT	OPEV
CUSTOMER TOTAL	CUSTOMER EQUIPMENT	CUCE
CUSTOMER TOTAL	CUSTOMER REQUEST	CUCR
CUSTOMER TOTAL	NONPAYMENT OF BILL	CUNP
CUSTOMER TOTAL	TAMPERING WITH SERVICE	CUTS
INTENTIONAL TOTAL	EMERGENCY REPAIRS	SCER
INTENTIONAL TOTAL	POLICE/FIRE/GOVT. AGENCY	SCGA
INTENTIONAL TOTAL	UNSAFE/HAZARDOUS CONDITIONS	SCHC
INTENTIONAL TOTAL	PROTECTION SYSTEM INTEGRITY	SCLC
INTENTIONAL TOTAL	MAINTENANCE/REPAIR/UPGRADE	SCMU
INTENTIONAL TOTAL	SCHEDULED CONSTRUCTION	SCSC
CUSTOMER	ACCESS TO EQUIPMENT DENIED	CUAD
CUSTOMER	INTERRUPTIBLE SERVICE TARIFF	CUIS

Other data slices were required to calculate the other required parts specifically for ARES versus IP, planned versus unplanned, and controllable versus uncontrollable.

Urban and Rural

Classification of urban and rural feeders is based on the customer density per line mile. Circuits with fewer than 50 customers per line mile are classified as rural. All others are classified as urban. Using this system, 240 circuits are customer owned, 556 circuits are classified as rural, and 443 feeders are classified as urban, as shown in Figure 7.



• Figure 7. Urban Versus Rural Histogram

Section 411.100 Reliability Obligations

a) *Each jurisdictional entity shall provide services and facilities that, in accordance with the Act and other applicable statutes, provide an adequate, efficient and reasonable level of reliability giving appropriate consideration to the costs and benefits of changing or maintaining the level of reliability.*

b) *Each jurisdictional entity shall plan, design, construct, operate and maintain its facilities, including equipment, apparatus, systems, and property, to prevent controllable interruptions of service and to meet the requirements of this Part, consistent with the requirements in subsection (a). If such interruptions occur, the jurisdictional entity shall reestablish service as soon as it can and in a time consistent with general safety and public welfare.*

c) *Each jurisdictional entity shall adopt and implement procedures for restoration of transmission and distribution services to customers after an interruption on a non-discriminatory basis without regard to the identity of the provider of power and energy.*

d) *Whenever a jurisdictional entity intends to interrupt electric service for the purpose of working on the system, the jurisdictional entity shall make reasonable efforts to notify those customers who may be affected by such interruption in advance of the construction, repair, or maintenance.*

e) *Each jurisdictional entity shall design its system according to generally accepted engineering practices, including consideration of normally expected weather, animal activity and other conditions.*

f) *Each jurisdictional entity shall adopt and maintain appropriate operating procedures and reliability related administrative procedures.*

IP takes seriously its obligation to provide safe, reliable electric service at a reasonable cost.. The Company has developed an enhanced distribution maintenance patrol, thus proactively identifying equipment for refurbishment, replacement, or repair prior to failure. IP has enhanced its crew call out procedures for anticipated storms in order to improve response time. The Company has adopted a new tool that provides ranking of reliability projects to achieve the most benefit per investment. The Company has created IT processes and systems to automatically rank projects. IP has continued to pursue mapping technology and is investigating the appropriate mapping solution for IP. Pilot programs have been initiated to geographically plot interruption information on circuits. A production version of a Geomedia based tool is used for map creation to provide maps for community notice prior tree trimming activities in those communities. An example is shown in Figure 11 on page 26.

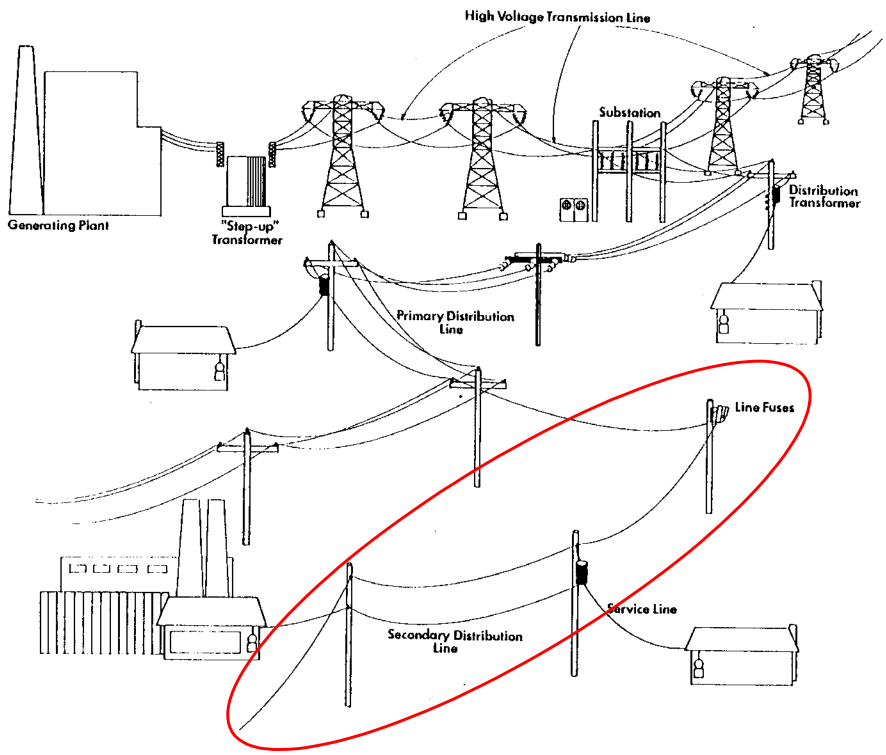
411.110 Record-keeping Requirements

a) *Required records. Except as provided in subsection (b) below, a jurisdictional entity shall maintain, for the most recent five-year period, the records listed below.*

1) *Records sufficient to determine a history of electric service interruptions experienced by each customer at the customer's current location. The records shall be sufficient to determine the information listed below for each interruption*.

A) Starting date of the interruption.
B) Starting time of the interruption.
C) Interruption duration.
D) Description of the cause of the interruption.
E) Operating areas affected.
F) Circuit number(s) of the distribution circuit(s) affected.
G) Number of customers affected.
H) Service account number of each customer affected.
I) Address of each affected customer location.
J) Name of each affected customer's electric energy supplier, if known.

IP has gone above and beyond the required data collection requirements of Part 411 and has added a table in the Company's TOS to track interruptions by "zone of protection" and "zone of interruption". Figure 8 provides an example of a zone of protection. All 588,288 of IP's electric customers are mapped to a zone of protection and a zone of interruption. This new feature allows IP to more accurately plan for necessary reliability improvements. Troubled zones are easily identifiable and appropriate funding can be committed to the precise area requiring reliability improvement.



• Figure 8. Zone of Protection

2) *Records showing, for each distribution circuit, the total number of customers served by the circuit at the end of each year.*

The Company retains interruption records based on the customer snapshot taken on December 31st of each year. In addition to the customer snapshot, the Company retains the connected model from that date. The total number of customers served by a circuit, as well as significantly more information, can be derived from the customer snapshot.

b) *Periods for which records are not required. A jurisdictional entity need not maintain records reflecting the information identified in subsection (a) for any period prior to calendar year 1994. A jurisdictional entity which, as of January 1, 1994, did not have the technical capability to collect and record some or all of the information identified in subsection (a) need not maintain records reflecting such information for any period prior to January 1, 1999. A jurisdictional entity serving retail customers in Illinois as of December 16, 1997, and that was exempted from the requirements of the Commission's electric service reliability policy (83 Ill. Adm. Code 410, Subpart C) as of that date, need not maintain records reflecting such information for any period prior to January 1, 2002.*

Section 411.120 Notice and Reporting Requirements

a) *Telephone or facsimile notice. A jurisdictional entity must provide notice by telephone or by facsimile transmission to the Consumer Services Division of the Commission when any single event (e.g., storm, tornado, equipment malfunction, etc.) causes interruptions for 10,000 or more of the jurisdictional entity's customers for three hours or more. After such interruptions have continued for three hours, a jurisdictional entity must provide notice within one hour when the notice would be provided during normal business hours, or within the first hour of the next business day. A jurisdictional entity shall provide updates every two hours during the normal business day until service is restored to all customers involved. To the extent that data and information are known, such notice shall include the data and information listed below.*

1) *An estimate of the number of customers the interruptions affect.*
2) *Starting date of the interruptions.*
3) *Starting time of the interruptions.*
4) *Duration of the interruptions.*
5) *Locations of the interruptions, described as precisely as possible in generally recognized and geographically oriented terms such as street address, subdivision, or community.*
6) *Description of the cause of the interruptions.*
7) *The date and time when the jurisdictional entity expects to restore electric service.*
8) *The name and telephone number of a jurisdictional entity representative the Commission Staff can contact for more information about the interruptions.*
9) *Customer call volume to the jurisdictional entity during the interruption as compared to normal call volume and the steps the jurisdictional entity is taking to address call volume.*

During calendar year 2000, customers in Illinois Power's service territory experienced two events that exceeded established limits. These events occurred on April 20, 2000 and August 17-18, 2000.

The ICC was notified of the April 20th event via telephone and e-mail. The event consisted of tornadoes, and high winds. Most outages were in Bloomington due to downed 34.5 kV structures (18), and distribution poles (80) and Jacksonville had 15 downed distribution poles.

Similarly, the ICC was notified of the August 17th event by e-mail. Subsequent to notification on the August 17th event, IP completed and submitted a storm summary report to the ICC on October 6, 2000. The August 17th event can be characterized by: extreme continued storms, with sustained high winds and lightning, causing extensive damage to IP's transmission and distribution facilities. The storms caused numerous poles and spans of wire to fail in several areas.

b) *Annual report. On or before June 1 of each year, each jurisdictional entity, except for jurisdictional entities exempt under Section 411.110(b), shall file with the Chief Clerk of the Commission an annual report for the previous calendar year submitted under oath and verified by an individual responsible for the jurisdictional entity's transmission and distribution reliability.*

1) *The data requirements incorporated in the annual report are not meant to replace timely reports on outages when they occur or are remedied as required by other provisions of this Part.*
2) *Supporting data used for more than one purpose or calculation need be submitted only once in each annual report, if submitted with clear cross-references. Data should be consistent and differences reconciled to the extent possible.*
3) *The annual report shall include the information listed below.*

A) A plan for future investment and, where necessary, reliability improvements for the jurisdictional entity's transmission and distribution facilities that will ensure continued reliable delivery of energy to customers and provide the delivery reliability needed for fair and open competition, along with the estimated cost of implementing the plan and any changes to the plan from the previous annual report.

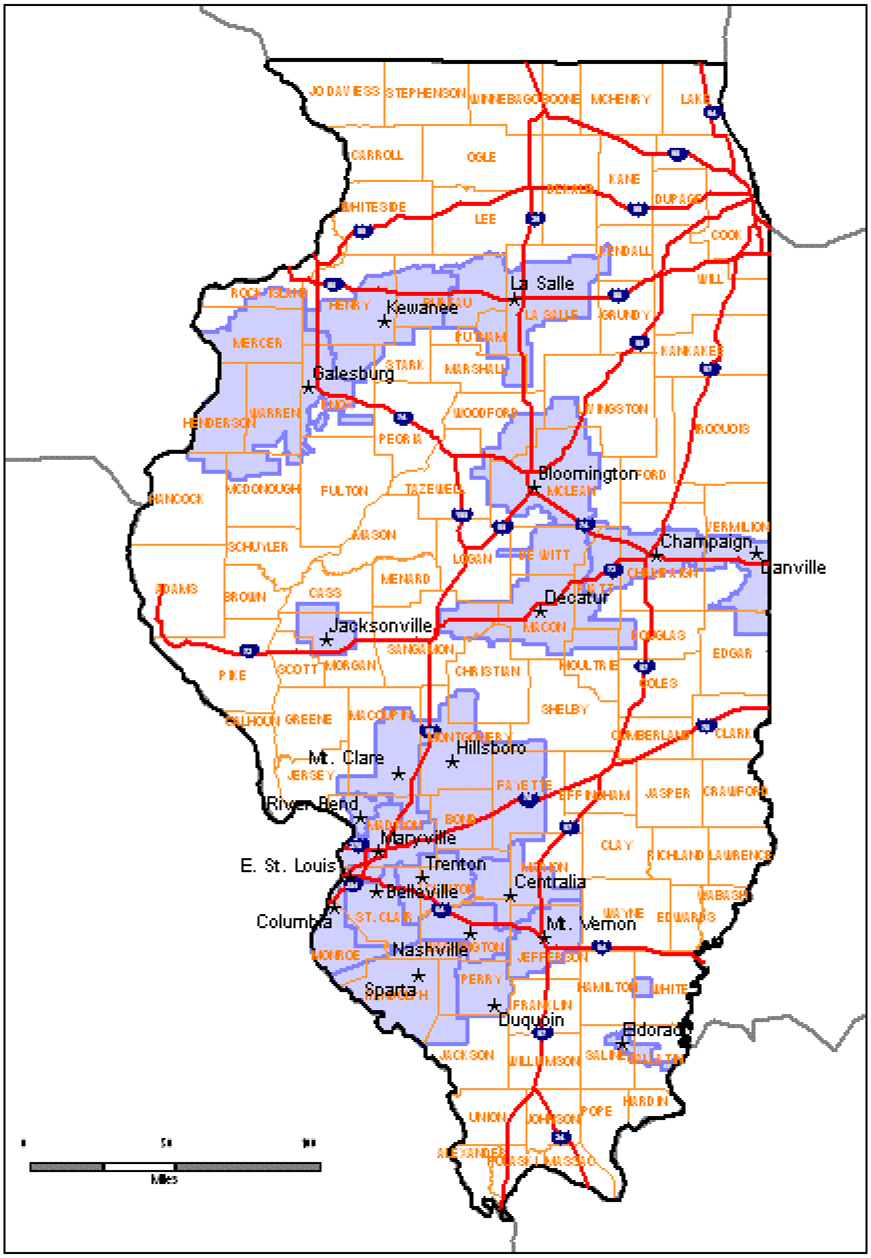
i) The plan must cover all operating areas, including a description of the relevant characteristics of each operating area and the age and condition of the jurisdictional entity's equipment and facilities in each operating area.

In 2000, Illinois Power provided electric service to 588,288 customers comprised of 64,225 commercial customers, 326 industrial customers, and 523,737 residential customers (as of 12/31/2000). Customers are distributed as shown in Table 3.

- Table 3. Customer Distribution by Geographic Area as of 12/31/00

Area	Commercial	Industrial	Residential
Galesburg	4,962	15	39,048
Kewanee	1,900	2	13,234
LaSalle	4,014	33	31,365
Bloomington	6,992	25	49,637
Champaign	7,798	37	62,385
Danville	3,335	27	29,346
Decatur	6,720	36	55,295
Jacksonville	1,493	11	11,614
Belleville	7,025	28	70,592
Centralia	2,185	14	14,304
Maryville	3,176	16	34,709
Granite City	2,158	26	21,284
Hillsboro	4,982	20	34,574
Mt Vernon	3,156	10	19,162
Sparta	2,782	12	21,527
River Bend	1,547	14	15,661

IP's service territory is geographically dispersed throughout the state as shown in Figure 9 below.



• Figure 9 Illinois Power's Service Territory

The Company's service territory covers approximately 15,000 square miles, or about one-fourth of the State. It consists mainly of rural areas and small towns with the majority of service lines providing service to residential, commercial, and agricultural loads. Approximately 93 percent of the Company's distribution system is overhead conductor with the other 7 percent being underground conductor.

ii) The plan shall cover a period of no less than three years following the year in which the report was filed.

The Company prepares detailed budgets for the current year only. Outlying years are typically an inflated annualized level of capital and O&M expenditures. Therefore, the reliability plan for 2001 provides a more detailed level of discussion pertaining to the specific activities that IP will undertake during the year to address reliability concerns. Similar details pertaining to expenditures for the years 2002 through 2004 is not available.

2001 RELIABILITY PLAN

The Company's annual planned expenditures, for both capital and O&M, establish levels that do not identify specific projects or programs. Rather, the plan establishes an overall level of expenditure available for construction, operation, and maintenance of the system in a given year. Once the annual plan is approved, the AM process is utilized to evaluate the justification for specific projects assigning a priority to those projects and committing the funding to complete the work. Existing policies, procedures, and programs that mandate a set level of preventative maintenance or inspections drive maintenance work. Corrective maintenance work is performed on an as needed basis.

Table 4 provides a breakdown of the 2001 planned Capital and O&M expenditures (*in constant 1998 dollars).*

• Table 4. 2001 Capital and O&M Planned Expenditures

Categories	Capital Expenditures (000s)	Maintenance Expenditures (000s)
Maintain Existing D System	$1,002	$13,334
Maintain Existing T System	$10,966	$2,041
Maintain/Upgrade/Operating Substations	$2,926	$4,728
Building New Distribution Substations	$3,141	$0
Rebuilds Due to Condition/Capacity – Distribution	$10,717	$618
Vegetation Management	$0	$11,986
Total	**$28,752**	**$32,707**

As a result of the Company's increased focus on reliability, the planned capital expenditures for distribution have been further detailed into the following categories as shown in Table 5. These reliability related categories, represent IPs initial effort to further describe detailed reliability related expenditures. This list is expected to be modified in the future to reflect IPs new emphasis on reliability mitigation programs. The Company also plans to develop similar categories for O&M expenditures.

• Table 5. Distribution Reliability Detail for Capital Expenditures

Capital Categories	Capital Expenditures (000s)
General Reliability (includes transformer replacement, overhead conductor replacement, voltage regulator and capacitor bank refurbishment and replacement, and secondary replacement and upgrade).	$2,479
Pole Replacement	$1,211
Underground Cable Replacement	$699
Capacity Related	$5,228
Protective Device Coordination Replacement and Upgrade	$211
Spacer Cable Replacement	$87
Animal Protection	$43
Lightning Protection	$70
Existing Substation Reliability	$3,716
New Substation Reliability	$1,141
Total	$14,886

IP has created a number of initiatives in 2001 to meet their commitment to reliability. The major commitments are detailed below.

Capacity Planning

Ongoing system planning studies are performed to help ensure the integrity of the T&D system. These efforts include preparing electric load forecasts, monitoring facility loadings, evaluating the system impacts of proposed generating units, and identifying required system reinforcements and expansions. Although not readily quantifiable, the reliability improvements associated with capacity related system reinforcements and expansions include the following:

- Reduced risk of equipment failure due to overload.
- Improved reserve capability and, correspondingly, reduced outage duration.
- Facility upgrades, which can also address condition issues.

Proactive Protective Device Coordination

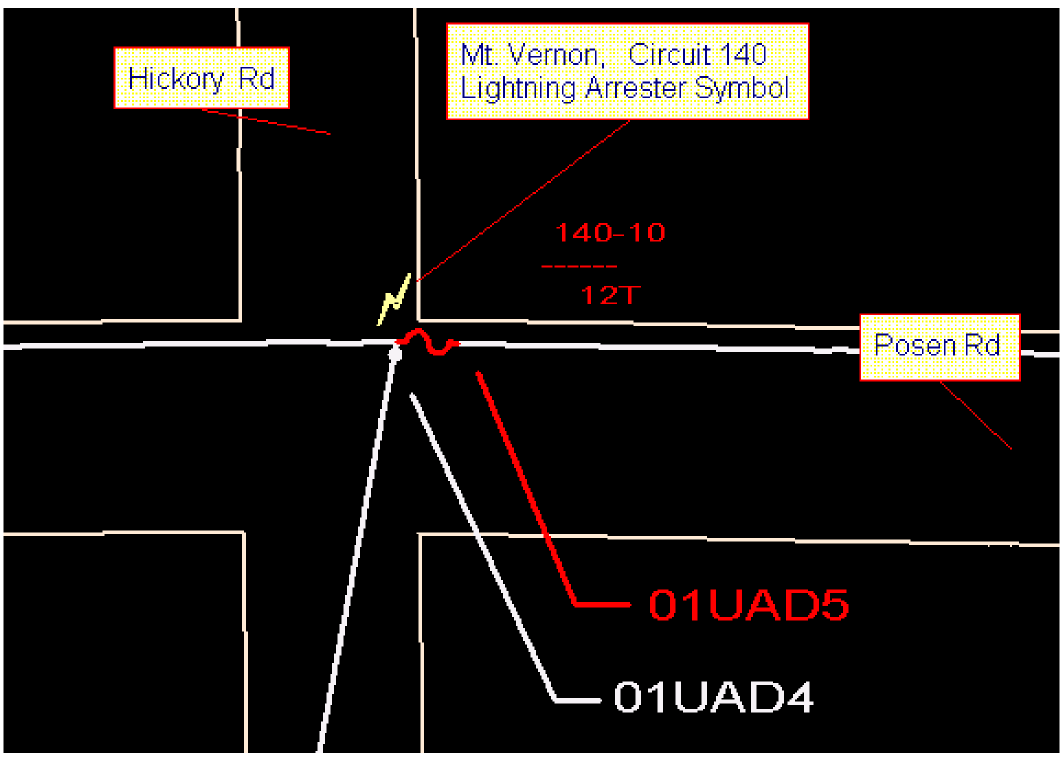
Illinois Power is in the third year of a distribution circuit proactive protective device coordination program. Under the program, approximately 10% of the Company's distribution circuits are analyzed each year. The scope of this effort includes identifying the system changes and upgrades needed to prevent protective device overload, ensuring proper coordination between protective devices, and avoiding the exceedance of the device interrupting capacity. The program is expected to reduce the frequency of customer interruptions by reducing protective device misoperations.

The number of circuits analyzed during the first two years of the program was actually greater than 10% each year. Based on analysis of 109 circuits during 1999, system improvements, totaling nearly $700,000, were completed in 2000. The analysis of 115 circuits during 2000 resulted in recommended improvements totaling over $1.4 million, which are scheduled for implementation in 2001. The program is on track for 2001 and approximately 10% of the circuits will be analyzed during the 2001 calendar year.

IP Reliability staff further augments protection and coordination by identifying the need for protective devices and their location for unprotected taps, thereby reducing the exposure to interruption for the remaining circuit. The focus of this effort has been on worst performing circuits.

Lightning Analysis

IP is taking a proactive approach to lightning analysis. A key component in lightning mitigation is arrester placement. Because arresters are a small dollar item, they are kept in common stock and used as necessary. Historically, no records were kept on exact arrester placement. IP has begun tracking arrester installations through the information delivery system (IDS) system. Figure 10 shows an example of the mapping technique that IP is using to track arrester placement.



• Figure 10. Lightning Arrester Placement Example

By tracking exact location, IP can perform more accurate lightning analysis. IP is also reviewing industry standards to insure that it's current lightning protection design is on par with the industry.

Substation RCM

IP added four major predictive tools to the substation maintenance process. While these tools have been a big help in improving reliability, the existing process has also been very productive. Many problems are found and corrected before they affect reliability or availability. The added tools are as follows:

1. Annual Infrared Substation Surveys
    a. checks for abnormal heating (e.g. high resistance connection)
    b. checks for lack of heating (e.g. plugged radiator)
2. Annual Airborne Ultrasonic Surveys
    a. checks for electrostatic discharge (e.g. cracked insulator)
    b. help locate air leaks (e.g. compressor system leak)
3. Biennial Contact Ultrasonic Surveys
    a. Checks for partial discharge and corona in transformers
    b. Checks for bearing problems in oil pumps
4. Three New Oil Analysis Protocols (applied per a schedule in the Energy Delivery Substation Department Maintenance Management Manual SM1.2)
    a. non-invasive tests indicating internal condition of:
        i. transformers,
        ii. tap changers,
        iii. breakers, and
        iv. dissolved gas analysis.
    b. The tests allow IP to extend maintenance intervals without sacrificing reliability.
    c. As shown in the examples below, these tests help prevent some catastrophic problems.

The tools listed in items 1 and 4 have provided the most reliability benefit. Use of these tools has prevented several catastrophic events from occurring. These circumstances are chronicled below.

Prevented Catastrophic Failure

<u>Aviston Transformer #2</u> – An oil test indicated a severe problem in a load tapchanger (LTC) on this transformer. The LTC was opened the next day and a collector ring & contact damage along with severe coking were found. As a result of this testing, IP was able to save a $550,000 transformer and avoid a major outage.

<u>Greenville Rt. 40 Transformer</u> - During a substation inspection, a loud audible noise from the transformer was noticed and reported. Additional testing was performed. Ultrasonic tests were 20 times higher than last year and a power factor test revealed winding movement. The transformer was changed out without either an outage to the customers or the additional cost of a failure cleanup.

<u>North Staunton Transformer #1</u> – An oil analysis indicated a large increase of Acetylene gas (highly explosive) in the transformer, creating a potentially dangerous situation. This gas is a result of arcing in the transformer. An ultrasonic survey indicated a partial discharge source. The transformer was taken out of service until an internal inspection could be made. The problem was discussed with the manufacturer, an internal inspection

was completed, and a bonding problem in the No-load tap changer was found. The problem was fixed in the field saving an $800,000 transformer.

Steelville Transformer #4 - An infrared survey indicated a hot bus tap to the X1 bushing. The crew replaced a cracked three inch bus connector. If the connector had broken, the phase would have fallen across and severely damaged a $800,000 transformer.

Greenville Line OCRs – An infrared survey found two line reclosers with internal heating on a circuit that feeds the local hospital. The line crew replaced the reclosers without an outage to the circuit.

Brokaw AB B204 - An infrared survey found two phases of this 138 kV switch's bus connectors hot. The connectors were replaced due to extreme damage. If this had failed in an uncontrolled manner, the delivery capability for energy to the Bloomington area would have been greatly impacted.

Latham AB B101 – An infrared survey found all three phases of this 138 kV switch abnormally hot. As a result of the infrared survey, this switch was scheduled for repair. This switch affects three of the six 138 kV lines feeding Decatur.

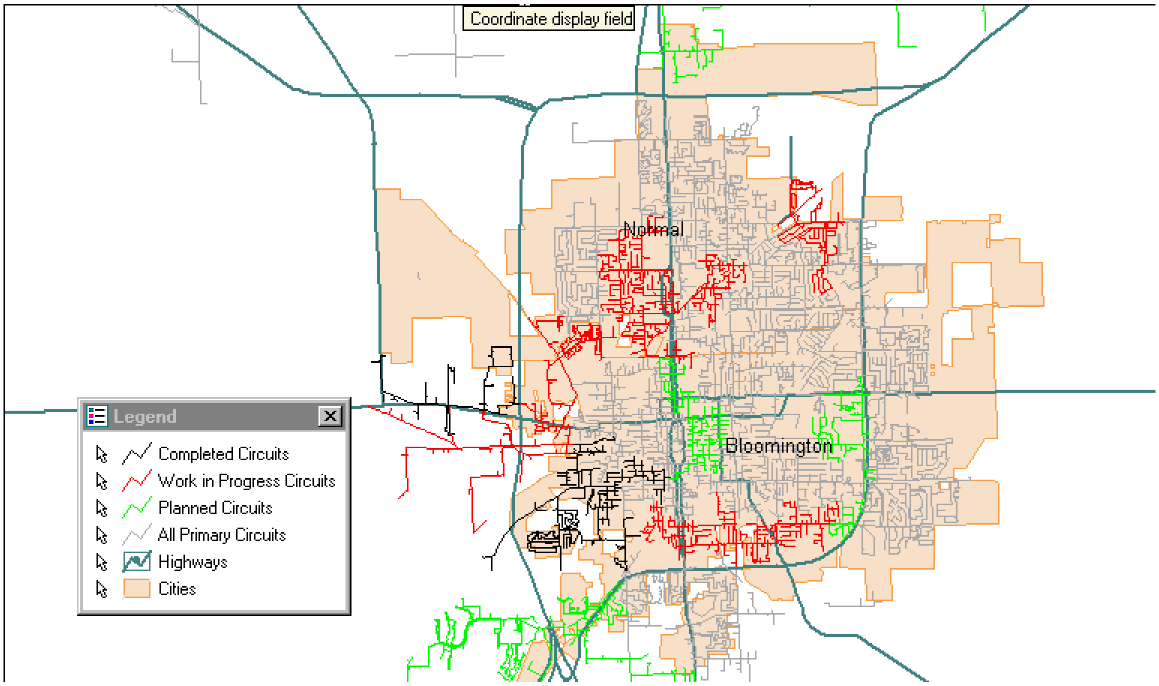
Forestry

Illinois Power's line clearance personnel use guidelines as described by the International Society of Arboriculture; ANSI A300; Arbor Day Foundation; and other professional organizations.

While there has been a consistent mitigation program in place since 1990, a re-focused program began in 1996. The program is designed around the concept of a circuit cyclical approach and achieving clearances that allow re-growth over a four-year period with minimal interference with the electrical conductor. The program is performed from the substation to and including the secondary. The expectations for the program are lower costs and improved reliability. Both expectations have been realized.

IP has been working towards a four-year cycle for all distribution circuits. IP plans to trim 180 circuits in 2001 and 211 circuits in 2002 to achieve a four-year cycle. In order to maintain a four-year cycle, IP intends to trim 196 circuits in 2003.

The forestry group is utilizing new mapping technology with a GeoMedia based application to create maps for internal and external purposes. Prior to trimming an Area, the forestry group plots color maps showing circuits where trimming is planned and has been completed. These maps are distributed to communities prior to commencement of trimming.



• Figure 11. Forestry Tool

In 1999, IP changed forestry contractors. Since that time, significant improvements in vegetation activity efficiency have been achieved. For the same expenditure, IP receives approximately 25 percent more tree trimming than prior to the change. This improvement was made through the new contractors use of improved equipment, tools, methods, and management.

IP is concerned not only with distribution line clearance, but also with transmission line clearance. To insure an outage free transmission system, aerial patrols are preformed in the spring and summer. During the fall/winter, forestry personnel check each identified trouble location and prepare plans to mitigate any potential problems.

Animal Protection

IP continues to purchase animal guards with all new transformers and continues to retrofit them on an as needed basis in the field. In 1998, IP established a program to protect substations from animal intrusions. Eleven substations were animal protected in 1998 at a cost of $150,000. Seven substations were animal protected in 1999 at a cost of approximately $90,000 in *constant 1998 dollars*. Nine substations were animal protected in 2000 at a cost of $120,000 in *constant 1998 dollars*. The Company plans to protect nine substations against animals in 2001 at an estimated cost of $128,000 in *constant 1998 dollars*

Circuit Patrols

IP has established a four-year cycle for distribution circuit patrols. The patrols were upgraded from a safety patrol to a maintenance patrol. Initial training was conducted for field leadership with their charge to train their personnel. Additional training will be given later this year to ensure consistency in reporting. New forms were created to better capture maintenance events. Electric Operations Supervisors ("EOS") and reliability personnel track the additional information in ECS to enable better management.

Emergency Restoration Time

In 1999, IP established an emergency restoration time goal ("ERT"). The goal is based on the percentage of manually entered ERT's versus system calculated ERT's on outages involving a transformer or higher device (i.e., fuse, recloser, breaker, switch, sectionalizer, substation bus). The interruptions used for this calculation must be at least 20 minutes in duration and the manually entered update must be done at least 10 minutes before the repair is made. These updates are fed to the voice response unit ("VRU") at the customer service center ("CSC") and are used to update customers when they call in about an outage. This process provides information to customers that IP is aware of the outage, and also conveys information regarding restoration time, thereby potentially eliminating any waiting period. Call-backs are used after the restoration is complete and to confirm that all affected customers are back in service. The call-back process is an automated process that only requires the customer to indicate, via the key pad on the phone, whether they are still without power or would like to speak with a customer service representative ("CSR"). IP is currently reviewing a "Proactive Dialer" application that will proactively notify customers of planned interruptions and/or to provide them updates on restoration times for planned and unplanned interruptions. IP also plans to use this system for notification/updates for customers on "Life Support".

The 1999 goal was 75% with actual performance at 77.8%. The 2000 goal was 80% and it was achieved. The 2001 goal is 80% and the performance is 85.7% through April.

2002 RELIABILITY PLAN

The planned capital and O&M expenditures for 2002 are shown in Table 6.

- Table 6. 2002 Planned Capital and O&M Expenditures

Categories	Capital Expenditures (000s)	Maintenance Expenditures (000s)
Maintain Existing D System	$ 830	$ 13,439
Maintain Existing T System	$11,784	$2,057
Maintain/Upgrade/Operating Substations	$ 2,935	$ 4,765
Building New Distribution Substations	$ 3,156	$0
Rebuilds Due to Condition/Capacity – Distribution	$ 10,771	$623
Vegetation Management	$0	$ 12,080
Total	**$29,477**	**$32,963**

2003 RELIABILITY PLAN

The planned capital and O&M expenditures for 2003 are shown in Table 7.

• Table 7. 2003 Planned Capital and O&M Expenditures

Categories	Capital Expenditures (000s)	Maintenance Expenditures (000s)
Maintain Existing D System	$ 832	$ 13,517
Maintain Existing T System	$9,030	$2,069
Maintain/Upgrade/Operating Substations	$ 2,940	$ 4,793
Building New Distribution Substations	$ 3,166	$0
Rebuilds Due to Condition/Capacity – Distribution	$ 10,803	$626
Vegetation Management	$0	$ 12,151
Total	**$26,771**	**$33,156**

2004 RELIABILITY PLAN

The planned capital and O&M expenditures for 2004 are shown in Table 8.

• Table 8. 2004 Planned Capital and O&M Expenditures

Categories	Capital Expenditures (000s)	Maintenance Expenditures (000s)
Maintain Existing D System	$ 835	$ 13,610
Maintain Existing T System	$7,971	$2,083
Maintain/Upgrade/Operating Substations	$ 2,946	$ 4,826
Building New Distribution Substations	$ 3,178	$0
Rebuilds Due to Condition/Capacity – Distribution	$ 10,846	$631
Vegetation Management	$0	$ 12,234
Total	**$25,776**	**$ 33,383**

(iii) The plan shall identify all foreseeable reliability challenges and describe specific projects for addressing each.

One of the biggest challenges IP has faced over the course of the last few years is the ability to engage qualified contract assistance. The contractors are used to shave peak work load. The shortage is caused, in part, by the amount of work being performed in Illinois and the lack of qualified contractors. Both last year and this year, it will be difficult for IP to spend their capital budget due to resource constraints.

Not only has IP been challenged by the ability to obtain qualified contract assistance, but also by the ability to hire and retain internal qualified personnel. The constantly changing landscape of mergers and acquisitions has made it difficult attract and retain qualified candidates. As a result, there are simply fewer qualified personnel available for employment.

Lightning is one of the largest contributors to customer interruptions on the IP system. IP is analyzing options to ensure proper lightning protection in all field locations. Standards have changed over time as new industry insights are developed regarding adequate distribution lightning protection. Industry journals have published findings that indicate the common utility practice of leaving “curly-q’s” of wire (additional lengths that allow easy relocation of hot line clamps otherwise known as long lead-lengths) is detrimental to lightning protection. IP is no different than other utilities in having once used this practice. A systematic program to reduce lead lengths on all devices would be cost-prohibitive. IP is reviewing historical interruption information to identify the best areas to update protection.

Another challenge for IP is in the area of animal protection. While IP has put programs in place to protect substations from animal intrusions and to purchase transformers with built-in animal protection, not all transformers/devices or substations are properly protected for animals today. A systematic program to protect all IPs transformers/devices/substations against animal intrusions would be cost-prohibitive. IP is reviewing historical interruption information to identify areas that require animal attention.

(iv) The plan shall provide a timetable for achievement of the plan’s goals.

The following table summarizes the 2001 initiatives.

• Table 9. Project Identified in IPs 2000 Plan

2000 Identified Initiatives	Status	Schedule	Comments
Continue to build new designs with adequate lightning and animal protection.	Ongoing	N.A.	IP is investigating new designs for lightning protection.
Continue to perform preventive maintenance	Ongoing	N.A.	None
Forestry	Ongoing	The Company will trim 180 circuits in 2001.	The Company continues to move towards a four-year trim cycle and will be on it by 2002.
2001 capital distribution budget.	Ongoing	N.A	None.
2001 distribution O&M budget	Ongoing	N.A.	None.
2001 capital transmission budget	Ongoing	N.A.	None
Perform Coordination Studies for 10% of Circuits.	Ongoing	N.A.	None
Enhanced Circuit Patrols.	Ongoing	Advanced training will be held by year end.	None.
Enhance ECS to capture Enhanced Maintenance Patrol Information.	Ongoing	By Year End.	None.
Establish Corporate-wide Reliability Goals	Ongoing	By Year End	None.
Ensure that all WPC's are adequately addressed	Ongoing	By Year End	None.
Develop an Operations Compliance group	Ongoing	By Year End	None.
Improve restoration times	Ongoing	By Year End	None.
Formalize the Central Reliability Group	Ongoing	By Year End	None.
Achieve ERT Goals	Ongoing	By Year End	None.
Investigate Lightning Protection Schemes.	Ongoing	By Year End	Goal is to evaluate current standards against industry standards.

(v) The plan shall report and address all unresolved reliability complaints about the jurisdictional entity's system received from other utilities, independent system operators, and alternative retail electric suppliers.

There were no unresolved complaints in 2000.

(vi) The plan shall report the specific actions, if any, the jurisdictional entity is taking to address the concerns raised in such complaints received from other utilities, independent system operators, and alternative retail electric suppliers.

There were no concerns raised by other utilities, ISOs, or ARES during 2000.

(vii) The plan must consider all interruption causes listed in Section 411.120(b)(3)(D).

Illinois Power's plan considers all interruptions.

(viii) The plan must consider the effects on customers and the cost of reducing the number of interruptions reported as required by Section 411.120(b)(3)(C).

The Company's business strategy is to provide safe, reliable, cost effective, and responsive service to all customers regardless of commodity supplier. The plans to improve reliability provided herein were prepared with the objective of minimizing the frequency of interruptions experienced by customers. No electric distribution system can be 100 percent free from interruption. IP is constantly seeking cost-effective techniques to construct, operate and maintain the system. If a customer experiences an interruption, the Company has and will continue to respond in an expedited manner to restore service. In support of that strategy, the results of the independently performed customer satisfaction survey show IP's residential and non-residential customers rated the Company 8.49 and 8.84, respectively, on a scale of 1 to 10 when asked about IP's overall provisioning of electric service.

When asked about the restoration of service when an outage occurs, IP's customers, both residential and non-residential, rated the Company at 8.09 and 8.39, respectively on a scale of 1 to 10.

B) A report of the jurisdictional entity's implementation of its plan filed pursuant to subsection (b)(3)(A) of this Section for the previous annual reporting period, including an identification of significant deviations from the first year of the previous plan and the reasons for the deviations.

The following table summarizes the initiatives that were identified in the Company's 1999 annual reliability report. The table also provides 1) a status of each initiative, 2) a schedule for remaining activities to be performed, and 3) an explanation for any variance from schedule.

• Table 10. Project Identified in IPs First Year Plan

1999 Identified Initiative	Status	Schedule	Comments
Continue to build new designs with adequate lightning and animal protection.	Ongoing	N.A.	New designs follow IP's lightning arrester and animal guard installation standards
Continue to perform preventive maintenance	Ongoing	N.A.	one
Vegetation management	Ongoing	The Company trimmed 151 circuits during 2000. Of the Company's 899 circuits, 706 were on a four-year cycle at the end of the calendar year 2000.	he Company ontinues to move owards a four-year im cycle and will be n it by the end of 002.
2000 capital distribution budget of $18.0 million (in *constant 1998 dollars*)	Actual expenditures of $13.4 million (in constant 1998 dollars)	Work that was scheduled for completion in 2000 had to be deferred due to the lack of qualified contractors. IP intends to perform the deferred 2000 work as well as the planned 2001 work in 2001.	ompany xperienced difficulty etaining qualified ontractor linemen fter 6/00. While the ompany continues o have difficulty etaining qualified ontractors, process nprovements have nproved the roductivity of vailable contractors.
2000 distribution O&M budget of $24.8 million (in constant 1998 dollars)	Actual expenditures of $24.4 million (in constant 1998 dollars)	N.A.	one.
2000 capital transmission budget of $9.9 million dollars (in constant 1998 dollars)	Actual expenditures of $8.9 million (in constant 1998 dollars)	N.A.	Company experienced difficulty retaining qualified contractor linemen after 6/00.
ransmission O&M udget of $3.8 million ollars (in constant 998 dollars)	Actual expenditures of $4.2 million (in constant 1998 dollars)	N.A.	None

1999 Identified Initiative	Status	Schedule	Comments
urther enhance TOS o have an up front iewer to better enable ystem dispatchers to solate problem areas n a circuit	oncept is being eevaluated against a GIS strategy.	By the end of 2001, a decision will be made regarding the method of providing a graphical front end to TOS	None
evelop a GeoMedia raphical TOS eporting system will be onstructed at a cost of pproximately $50,000	rototype completed.	Evaluation of a Mapping Solution for IP is ongoing.	The forestry group is using a Geomedia based application for producing color coded maps.
stablish systems and eports to allow TOS to dentify problem areas	ompleted	None	None
evelop/implement the se of reliability entered maintenance r substations.	reliability entered maintenance rogram for substations is in rogress.	Ongoing	See Section Substation RCM on page 24.
Create and finalize the details of a procedural database that will track and manage procedural work.	Ongoing	Ongoing	The newly formed centralized reliability and Operations Compliance groups are working together to establish an acceptable system to track and manage procedural work.
Perform aerial patrols on the sub-transmission and transmission system to identify problem areas	Performed as planned.	Annual	Problem Areas Identified.

C) *The number and duration of planned and unplanned interruptions for the annual reporting period and their impacts on customers.*

The number and duration of planned and unplanned interruptions during calendar years 1998, 1999 and 2000 are shown in Table 11.

• Table 11. Exhibit 411.120.b.3.C

Year	Category	Duration (hr)	CI	Events
2000	Unplanned Interruptions	2,718,298	968,205	19,262
1999	Unplanned Interruptions	1,887,374	788,405	18,221
1998	Unplanned Interruptions	6,669,027	1,464,080	27,524
2000	Planned Interruptions	128,488	99,168	3,585
1999	Planned Interruptions	119,584	112,350	4,369
1998	Planned Interruptions	404,030	116,916	4,321

As can be seen in Table 11, the number of planned events in 2000 decreased by approximately 18 percent from previous years. At the same time the customers interrupted decreased by approximately 12 percent, but the customer minutes interrupted increased by approximately seven percent.

D) The number and causes of controllable interruptions for the annual reporting period.

A controllable outage is defined as "an interruption caused or exacerbated in scope and duration by the condition of facilities, equipment, or premises owned or operated by a utility, or by the action or inaction of persons under a utilities control and that could have been prevented through the use of accepted construction, and maintenance practices".

Table 12 provides the number and causes of controllable interruptions for the years 1998, 1999 and 2000. In order to comply with this section, IP further developed controllable definitions by interruption cause category. Due to concerns raised in past ICC reviews, IP plans to reevaluate each controllable cause code definition.

• Table 12. Exhibit 411.120.b.3.D

Interruption Cause Category	Number of Controllable Outages			Number of Controllable Customer Interruptions		
	2000	1999	1998	2000	1999	1998
Accident by IP or IP Contractor	43	107	3	4,015	16,069	84
Animals, Birds, Snakes, Other	2	2	130	83	2	3,883
Broken Fuse Link	91	83	0	985	1,269	0
Dig-In by IP or IP Contractor	6	10	16	67	125	985
Extreme Cold	11	35	0	197	2,119	0
Extreme Heat	14	77	13	251	3,918	936
Ice	35	81	0	1,387	7,029	0
Maintenance/Upgrade/ Repair	19	65	0	157	1,620	0
OH Equipment Contamination	1	1	0	1	1	0

Interruption Cause Category	Number of Controllable Outages			Number of Controllable Customer Interruptions		
OH Equipment Malfunction	1	73	57	9	2,631	2,424
Scheduled Construction	0	1	0	0	10	0
Substation Equipment	0	1	11	0	1	2,061
Switching Error	18	29	0	8,031	5,511	0
Testing Error	0	6	0	0	1,375	0
Transmission System Outage	0	1	8	0	1	7,882
Tree Contact Primary	91	355	683	4,479	18,654	55,513
Tree Contact Secondary	107	151	523	1,100	1,702	11,493
Tree Contact Service Drop	0	1	0	0	1	0
UG Equipment Malfunction	2	1	157	2	66	3,978
UG Failure	498	611	0	7,797	12,880	0
Unclassified Error	62	122	0	2,410	733	0
Unknown	178	311	671	8,716	19,386	55,051
TOTAL	1,179	2,214	2,272	39,687	95,103	144,290

As Table 12 shows, there was a significant decrease in the number of controllable interruptions and the number of customers interrupted due to controllable interruptions during 2000.

Illinois Power's operations and maintenance standards, procedures, and training stress approaches to reduce or prevent controllable outages while working safely. IP's apprentice linemen are required to attend a training program that can last up to 3 ½ years before they are fully recognized as a journeyman. After the apprentice program, the journeymen continue to receive on-the-job training. This training stresses the correct, safe way to work and operate distribution equipment. The training helps to prevent mistakes that could cause an outage. IP also has a "hurt alert" program in place that is routed to every line department. This program communicates lessons learned from accidents and is aimed at preventing future accidents. Further, IP has a vegetation management program that focuses on preventing outages. Technology has been developed to track forestry outage status on a daily basis. IP patrols its transmission lines twice a year to identify problem areas that need to be trimmed immediately. The statistics clearly demonstrate that IP's forestry programs are effective in reducing outages.

E) Customer service interruptions that were due solely to the actions or inactions of another utility, another jurisdictional entity, independent system operator, or alternative retail electric supplier for the annual reporting period.

Information relating to non-IP events reported in 1998 is not available. In 1999, information was reported about customer interruptions and number of events. Customer minutes interrupted resulting from the 1999 non-IP events is not available. For the 2000 report, the number of events, the number of customers interrupted, and the customer minutes interrupted are available and reported.

• Table 13. Exhibit 411.120.b.3.E

Year	Cause of Interruptions	Customer Minutes Interrupted	Customer Interruptions	Events
2000	OPERATING EVENT	250,411	4,647	5
2000	LOSS OF SUPPLY	3,713,084	17,649	40
1999	OPERATING EVENT	N/A	4,002	19
1999	LOSS OF SUPPLY	N/A	11,822	11

There were significantly more "loss of supply" events in 2000 than experienced in 1999. This is a concerning statistic and one that IP will closely monitor.

F) A comparison of interruption frequency and duration for customers buying electric energy from the jurisdictional entity versus customers buying electric energy from another utility or alternative retail electric supplier for the annual reporting period. A jurisdictional entity may base this comparison on each customer's supplier as of December 31 of each year. A jurisdictional entity need not include this information for customers whose electric energy supplier is not known to the jurisdictional entity.

Prior to 2000, IP's systems did not accurately track ARES customers. This problem was solved in 2000.

• Table 14. Exhibit 411.120.b.3.F

	2000 Illinois Power	2000 ARES	1999 Illinois Power	1999 ARES	1998 Illinois Power	1998 ARES
Number of Controllable Customer Interruptions	39,652	36	63,258	0	144,290	0
Number of Uncontrollable Customer Interruptions	1,056,272	585	724,393	0	1,319,790	0
Controllable Interruption Minutes	3,850,191	2,287	6,686,224	0	17,645,821	0
Uncontrollable Interruption Minutes	171,162,034	100,254	106,623,549	0	382,495,809	0

G) A report of the age, current condition, reliability and performance of the jurisdictional entity's existing transmission and distribution facilities, which shall include, without limitation, the data listed below. In analyzing and reporting the age of the jurisdictional entity's plant and equipment, the jurisdictional entity may utilize book depreciation. Statistical estimation and analysis may be used when actual ages and conditions of facilities are not readily available. The use of such techniques shall be disclosed in the report.

The data shown in Table 15 and pertaining to the age of the transmission and distribution systems has been extracted from the Company's continuing property records. The data is presented in the format requested by the Staff of the Commission.

- Table 15. Transmission Equipment - Average Age

Account Title	Average Age Years	Remaining Life Years	Life 0 to 10 Years	Life 11 to 20 Years	Life 21 to 30 Years	Life 31 to 40 Years	Life > 40 Years	Total
Structures and Improvements	20.0	45.3	4,069,098	1,299,434	2,197,376	1,470,122	1,434,371	10,470,401
Station Equipment	19.6	37.2	59,220,497	32,526,483	48,021,680	20,024,225	21,525,729	181,318,614
Poles Towers and Fixtures	4.1	10.3	257,901,909	9,632,665	6,094,878	3,919,399	3,133,800	280,682,651
Overhead Conductor and Devices	3.7	22.0	236,531,882	4,582,611	4,564,164	3,435,860	2,986,867	252,101,384
Underground Conduit*	NA	18.8	16,283,249	0	0	0		16,283,249
Underground Conductor and Devices*	NA	14.5	135,634,120		0	0	0	135,634,120
Line Transformers	14.9	30.7	115,190,306	44,101,393	43,163,421	25,141,112	9,344,100	236,940,332
Services*	NA	20.3	112,787,520					112,787,520
Installation at Customer Premises**	NA	NA	0	0	0	0	0	0

• Table 16. Distribution Equipment Average Age

Account Title	Average Age Years	Remaining Life Years	Life 0 to 10 Years	Life 11 to 20 Years	Life 21 to 30 Years	Life 31 to 40 Years	Life > 40 Years	Total
Structures and Improvements	57.0	30.8	1,470,239	555,134	2,362,252	434,935	592,963	5,415,523
Station Equipment	51.0	26.6	38,842,903	10,864,123	31,739,948	10,521,990	12,159,396	104,128,360
Towers and Fixtures	45.0	21.9	977,559	586,384	4,917,291	8,059,950	1,410,725	15,951,909
Poles and Fixtures	49.0	26.2	15,476,966	15,236,812	20,892,297	4,220,651	5,398,021	61,224,747
Overhead Conductors and Devices	46.0	24.2	15,605,789	8,542,573	21,585,610	9,530,965	6,190,458	61,455,395

*These accounts are mass property and asset records are not kept by vintage.
** IP does not have any assets categorized in this account.

The information provided in these tables reflects data based upon the Company's last depreciation study, which was approved by the Commission in Docket No. 91-0147. The information pertaining to "Average Age Years" and "Remaining Life Years" will remain constant until such time as another study is completed. The Company is currently in the process of conducting a new depreciation study for the electric business. It should be noted that the Company does not maintain data pertaining to the vintage of mass property.

i) *A qualitative characterization of the condition of the jurisdictional entity's system defining the criteria used in making the qualitative assessment, and explaining why they are appropriate*

The Company conducts a number of periodic patrols and performs corrective and preventative maintenance to keep the T&D system operating as designed. In addition, the Company has established an Operations Compliance organization that has been charged with monitoring whether operations, maintenance and construction activities are being performed in a manner consistent with Company policies, procedures, programs and processes. Based upon the results of these patrols and maintenance activities, the Company believes that the T&D system has been constructed, operated and maintained in a manner that should ensure safe and reliable operations of the system.

ii) *A summary of the jurisdictional entity's interruptions and voltage variances reportable under this Part, including the reliability indices for the annual reporting period.*

This was reported in Section 411.120.b.3.H.

iii) The jurisdictional entity's expenditures for transmission construction and maintenance for the annual reporting period expressed in constant 1998 dollars, the ratio of those expenditures to the jurisdictional entity's transmission investment, and the average remaining depreciation lives of the entity's transmission facilities, expressed as a percentage of total depreciation lives.

The requested information pertaining to the transmission plant is given below.

• Table 17. Transmission Construction and Maintenance

Item	1998	1999	2000
Transmission Construction and Operating and Maintenance Expenditures (in constant 1998 dollars) (000s)	$7,766	$6,100	$13,100
Transmission Investment (000s)	$320,979	$241,100	$248,176
Annual Expenditure Represents X% of Total Transmission Investment (Line 1/Line 2)	2.42%	2.53%	5.28%
Transmission System Average Remaining Life	14.2 – 18.7 yrs	14.2 – 18.7 yrs	14.2 – 18.7 yrs
Total Depreciation Life of Transmission Plant	45 – 57 yrs	45 – 57 yrs	45 – 57 yrs
Percentage of Total Depreciation Life (Average of Line 4/Average of Line 5)	32.25%	32.25%	32.25%
Note: The reclassification of certain transmission plant based upon application of FERC 7 factor test is reflected in 1999 and 2000.			

iv) *The jurisdictional entity's expenditures for distribution construction and maintenance for the annual reporting period expressed in constant 1998 dollars, the ratio of those expenditures to the jurisdictional entity's distribution investment, and the average remaining depreciation lives of the entity's distribution facilities, expressed as a percentage of total depreciation lives.*

The requested information pertaining to the distribution plant is given below.

• Table 18. Distribution Construction and O&M

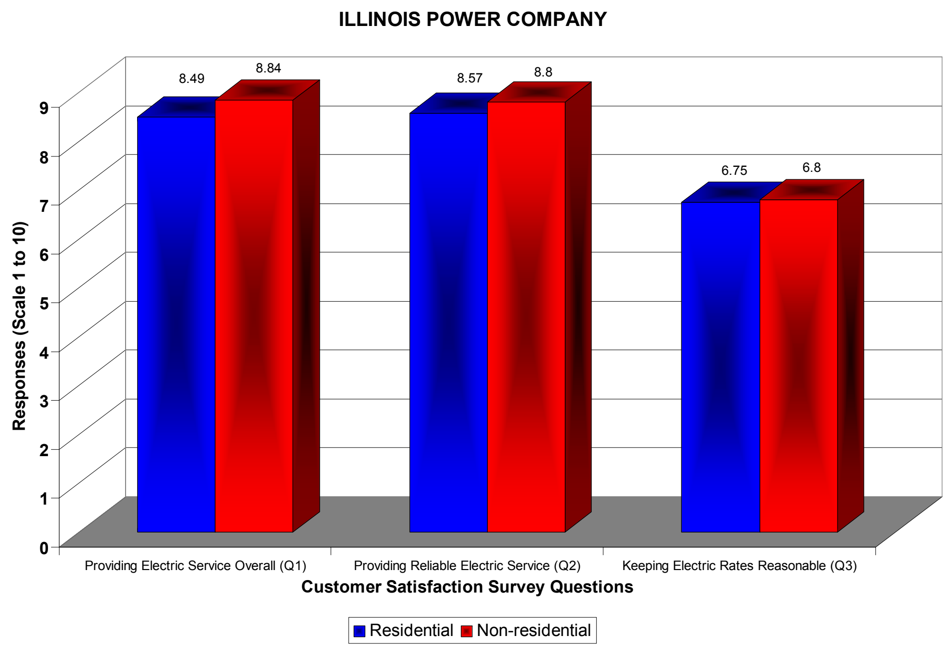
Item	**1998**	**1999**	**2000**
Distribution Construction and Operating and Maintenance Expenditures (in constant 1998 dollars) (000s)	$38,400	$37,200	$37,800
Distribution Investment (000s)	$1,029,270	$1,164,961	$1,226,218
Annual Expenditure Represents X% of Total Distribution Investment	3.73%	3.19%	3.08%
Distribution System Average Remaining Life	10.6 – 26.9 yrs	10.6 – 26.9 yrs	10.6 – 26.9 yrs
Total Depreciation Life of Distribution Plant	10.6 – 60 yrs	10.6 – 60 yrs	10.6 – 60 yrs
Percentage of Total Depreciation Life	53.12%	53.12%	53.12%
Note: The Distribution Construction and Operating and Maintenance Expenditures EXCLUDE forestry expenditures.			

v) *The results of a customer satisfaction survey completed during the annual reporting period and covering reliability, customer service, and customer understanding of the jurisdictional entity's services and prices.*

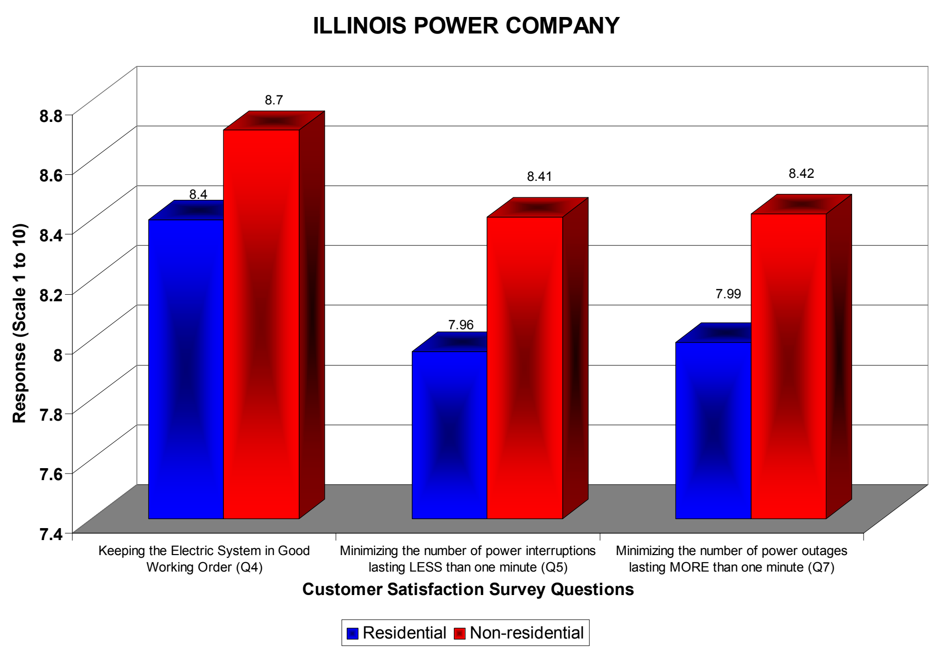
In 1998, as part of the adoption of Administrative Code Part 411, the Commission adopted a requirement that a standardized customer survey be developed and utilized by each electric utility. The ICC initiated a rulemaking to design and approve the survey. Opinion Dynamics Corporation ("ODC") was selected via a competitive bidding process to assist with the development and conduct of the initial survey.

ODC conducted a survey of 600 residential and 400 non-residential customers. The survey addressed topics such as overall satisfaction; reliability performance; customer service performance; understanding of services; tree trimming performance; billing; and demographics/firmographics. The surveys were conducted between October 24, 2000 and December 6, 2000. The following graphs provide summaries of the results of this initial survey. Given that this was the initial survey, year-to-year comparisons of similar information cannot be provided. Figure 9 to Figure 16, below, show survey results. A complete copy of the customer satisfaction survey conducted and prepared by ODC is provided as Attachment 1 to this report.

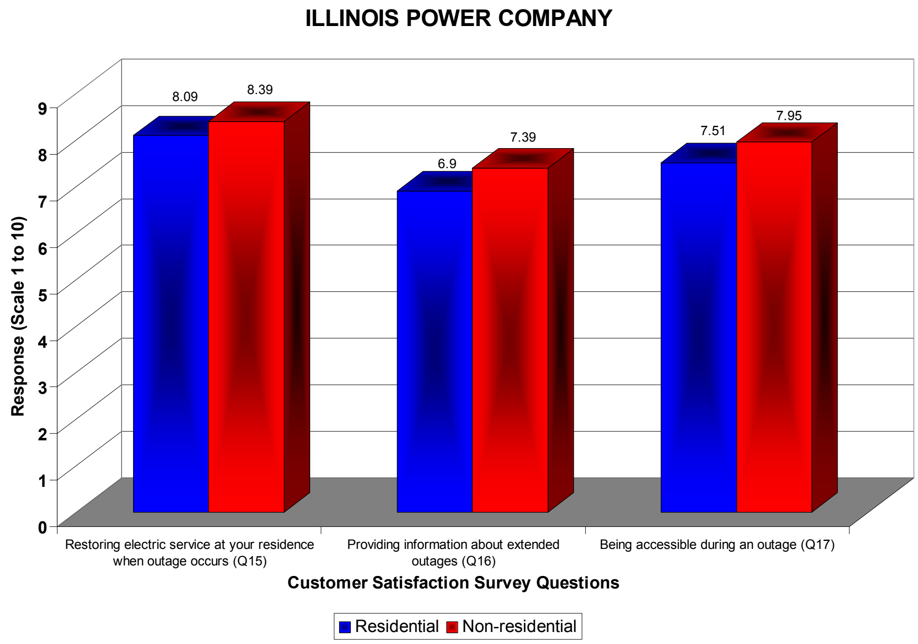
As shown in Figure 12, Illinois Power customers are satisfied with their electric service and reliability. Next year there will be a comparison year based on the same survey and trending information will be available.



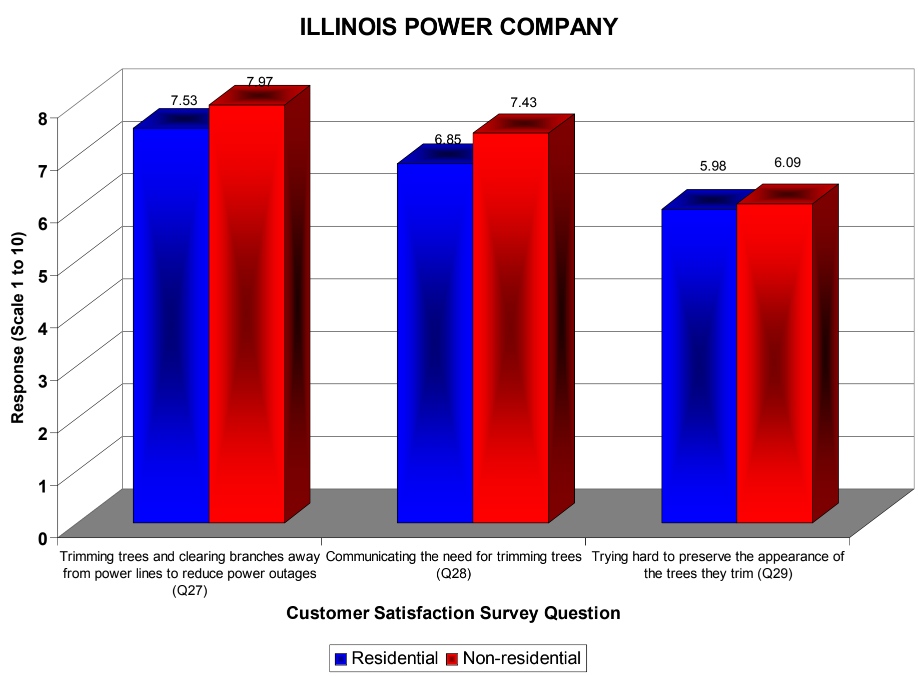
• Figure 12. Customer Satisfaction Survey Response to Q1-Q3



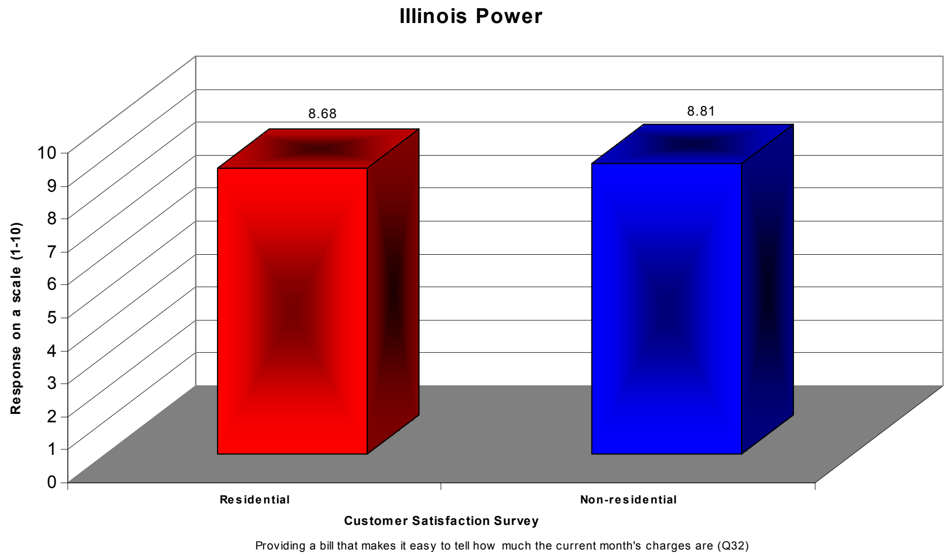
• Figure 13. Customer Satisfaction Survey Response to Q4,Q5, Q7



• Figure 14. Customer Satisfaction Survey Response to Q15-Q17



• Figure 15. Customer Satisfaction Survey Response to Q27-Q29



• Figure 16. Customer Satisfaction Survey Response to Q32

The survey did identify areas in which IP needs to needs to investigate its current practices, procedures and policies. For example, the Company received lower rankings in such areas as: providing information about extended outages (6.90); and familiarity with issues such as different bill payment options (63.2 percent); having a toll-free number to report power outages (63.0 percent); being available 24 hours a day, seven days a week by phone in the event of a power outage (61.9 percent); trimming trees to reduce the occurrence of power outages (54.6 percent); and reporting information about extended power outages to the news media to keep customers informed (26.8 percent). The ratings provided pertain to residential surveys only. IP will explore ways by which to better educate its customers on the various services that the Company offers.

The Company no longer conducts its own internal customer surveys. Therefore, no comparative survey data is available for calendar year 2000 to reflect trends.

vi) An overview pertaining to the number and substance of customers' reliability complaints for the annual reporting period and their distribution over the jurisdictional entity's operating areas.

Table 19 shows the customer complaints made during 2000.

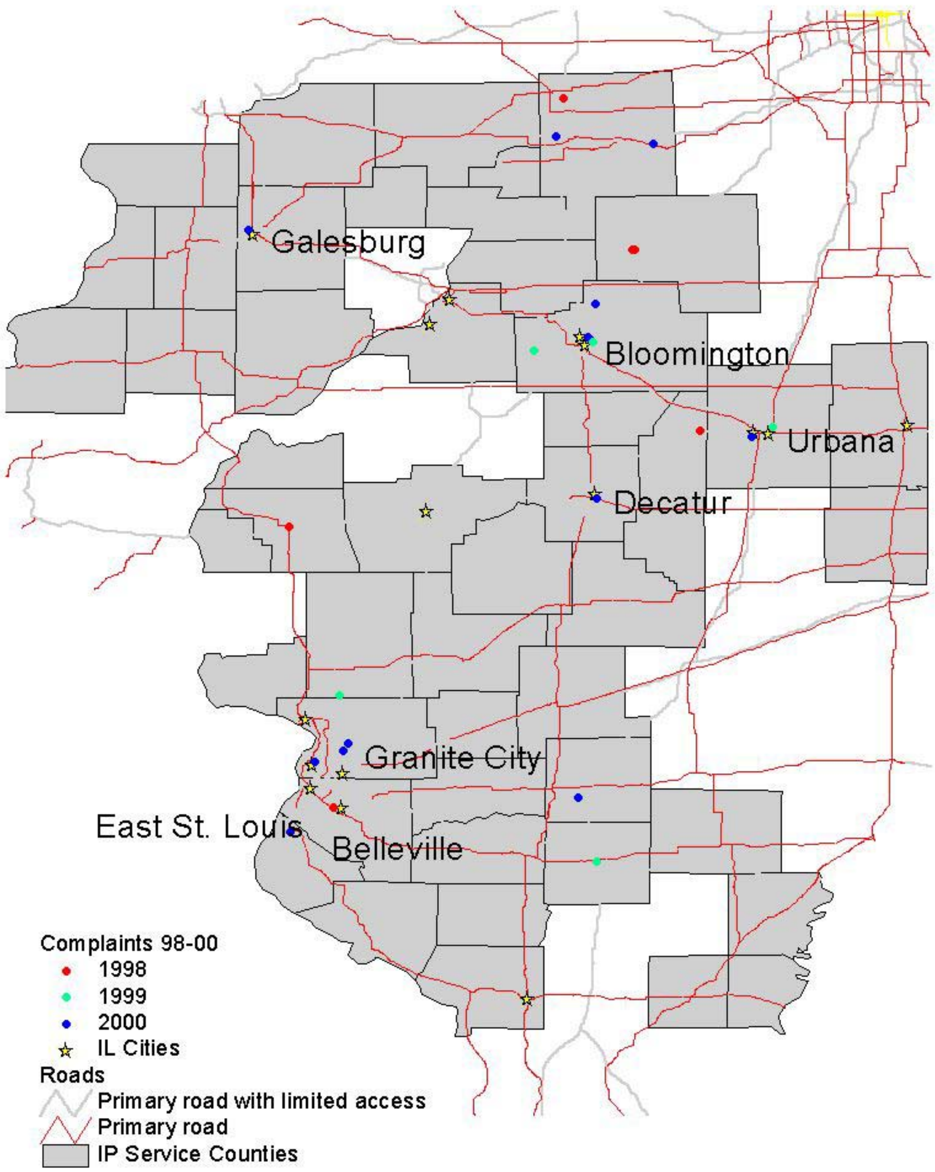
• Table 19. 2000 Customer Complaint Summary

Customer Complaints 2000	**Explanation**
Christine Boswell Marseilles Request to replace 9/11/2000	Customer has older 3 wire 60 amp service that she wanted replaced. We explained to her that she must first upgrade the service entrance before we could replace the older service wire. She will advise us if she upgrades her service entrance.
Steve Crites Granite City Flickering lights 8/21/2000	Most of customer reliability problems are storm related; one outage caused by a fire at Venice Power Plant which affected the transmission line serving the area; some problems due to energy load imbalance condition which has been mitigated.
Citation Oil & Gas Odin Frequent curtailments 3/27/2000	All curtailments taken at the Salem Plant were in accord with the Power Supply Agreement between IP and the customer, Citation Oil & Gas
Citation Oil & Gas Odin Objects to outage 6/30/2000, 8/14/2000	The specific outage of 6/30 was caused by CIPS line outage. A subsequent outage on 7/31 was caused by loose jumper cables at the Texas Substation.
Kevin Drohan Normal Frequent outages 8/31/2000	Outages were isolated to several spans of underground cable in the subdivision, which was replaced by IP the first of October 2000. The Company mailed a letter of explanation on the outage cause and mitigation to all customers in the subdivision affected by this condition.
Linden Harms Normal Frequent outages 8/31/2000	Outages were isolated to several spans of underground cable in the subdivision, which was replaced by IP the first of October 2000. The Company mailed a letter of explanation on the outage cause and mitigation to all customers in the subdivision affected by this condition.

Customer Complaints 2000	Explanation
Andreas Matoesian Edwardsville Outage of 8/27/00 8/30/2000	Customer was out of service for 24 hours and concerned that IP records did not show her "Life Support". Reason: the customer failed to complete the annual re-certification of life support needs; therefore, the account was removed from the "life Support" registry. After notification from customer the re-certification was processed and the account updated as "Life Support". An IP customer service administrator reminded the customer of their responsibility to have alternate plans in the event of prolonged power outages.
Charles McGorray Decatur Frequent outages 6/16/2000	Service to customer's neighborhood was affected momentary "blinks". The level of service was improved greatly after the company isolated an industrial load from the line serving the customer's neighborhood.
Sharon Pettegrew Champaign Excessive outages 9/19/2000	Replaced underground primary cable.
Ed Raycraft Hudson Outage for long period. 12/18/2000	Repairs were awaiting the delivery of a replacement transmission pole from another location. To prevent another delay in the event of similar outages a spare replacement pole was delivered to a nearby storage area.
Robert Swiatek Edwardsville Frequent outages 10/26/2000	As explained to customer, four (4) recent outages he experienced were animal related, blown transformer, fuse, and weather related (2). While these outages are beyond IP's control, our commitment is to restore service as quickly as possible.
John Sekula LaSalle Excessive outages 9/13/2000	Line providing service to customer's subdivision was replaced 9/18/00 and will improve future reliability.
Cathy Schnelker Urbana Brief outage 12/28/2000	There was a momentary outage caused by a small animal in transformer causing line fault. Customer was concerned it was "Y2K" related.

Customer Complaints 2000	Explanation
Gerald Whitmore Galesburg Poor service quality 9/11/2000	Most of the outages recorded on this service are momentary OCR operations. Actual measured outages are few.
Jim Wilson Columbia Voltage complaint 8/17/00.	Recording voltmeters set for seven days. The results demonstrate steady voltage at 122 volts. No voltage drop or blinks were noted during this period.

Figure 17 shows the geographic location of the complainants.



• Figure 17. Customer Complaint Locations for 1998-2000 *vii) The corresponding information, in the same format, for the previous three annual reporting periods, if available*

Table 20 and Table 21 show the 1998 and 1999 customer complaints.

- Table 20. 1999 Customer Complaint Summary

1999 Customer Complaints	Explanation
Laura Carlanell Urbana 6125487896 Repeated Outages 10/14/99	IP's prior responses to past outages with repairs on the underground cable did not fix the problem. After resolving issues of right-of-way with out of town owners of the trailer park, the Company replaced the underground cable and transformer on 11/12/99.
William Drobny Bloomington 4975166551 Frequent Outages 12/10/99	The Company recognized a need to improve reliability of service in customer location and in fact commenced doing so late in 1998 and early 1999. IP rebuilt the main line in this neighborhood and installed new underground switchgears to balance load for improved reliability. Responding to the recent outage we replaced faulty U.G. primary cable, installed new transformer, and reset breaker settings to help isolate any future problems. Work completed by 12/17/99.
Steven Janssen Bunker Hill 9976134923 Voltage Complaint 9/6/99	Complaint isolated to customer premise. IP had repeatedly responded to customer complaints of "power surges" and "flickering lights" in 1999. Each time we advised the customer of his need to upgrade his old 100-amp service, which has corroded connections, with newer 200-amp service entrance.
Jay Lewis Mt. Vernon 0028769735 Flickering Lights	Customer outage history confirms some outages caused by small animals getting into IP equipment. To help mitigate the problem the Company developed a plan to: trim trees; add protective equipment and squirrel guards; install two line fuses; and reset relay settings. Work to be completed after 1/3/00.
William Rennie Danvers 1373663552 Low Voltage 1/11/99	A 1/1/99-winter storm caused damage to IP's transmission line that serves Danvers. At this time, service to Mr. Rennie had been interrupted, and his subsequent claims for damages to his refrigerator were denied by IP.

• Table 21. 1998 Customer Complaint Summary

1998 Customer Complaints	Explanation
Bernadine Cage Belleville 9077803116 Frequent Outages 6/29/98	System-wide problems identified on circuit. All customers on circuit notified of IP plan for system improvements and modification were completed in late 1998.
Merna Calabrese Graymont 4572607646 Voltage complaint 3/30/98	Problems caused by 150-hp motor owned and operated by Graymont Co-op. Through the joint efforts of the Co-op, motor manufacturer, and IP arrangements were made to complete equipment modifications at the Co-op, which eliminated the voltage problem.
Donald Douglas White Heath 5967859379 Outages 12/4/98	Isolated mechanical failure with 69kV jumper, which burnt and caused the outage. Repairs made.
Jennie Heflin Alexis Extended outage 9/1/98	Severe storms hit the northern Illinois region on June 29, which caused widespread outages for an extended period. Customer claim for loss of food was denied.
Thomas Honey Jacksonville 3926665404 Frequent outages 1/8/98	Outages caused by various factors, including weather, equipment failure, and animal interference. Six outages for six total hours recorded in previous 12 months did not appear excessive.
Randy Mundschenk Graymont 8677790973 Voltage 5/27/98	See remarks in Merna Calabrese complaint.
Michael Phalen Mendota 4726395977 Outages 7/7/98	Isolated complaint; replaced terminations and tightened connections around customer premises to help alleviate momentary outages; service restored within 30 min. of complaint.
Peggy Swellen Graymont 0009442960 Voltage 6/8/98	See remarks in Merna Calabrese complaint.

Paul Schaffer Graymont 9819697829 Voltage 5/13/98	See remarks in Merna Calabrese complaint.

H) A table showing the achieved level of each of the three reliability indices of each operating area for the annual reporting period (provided, however, that for any reporting period commencing before April 1, 1998, a jurisdictional entity will not be required to report the CAIFI reliability index).

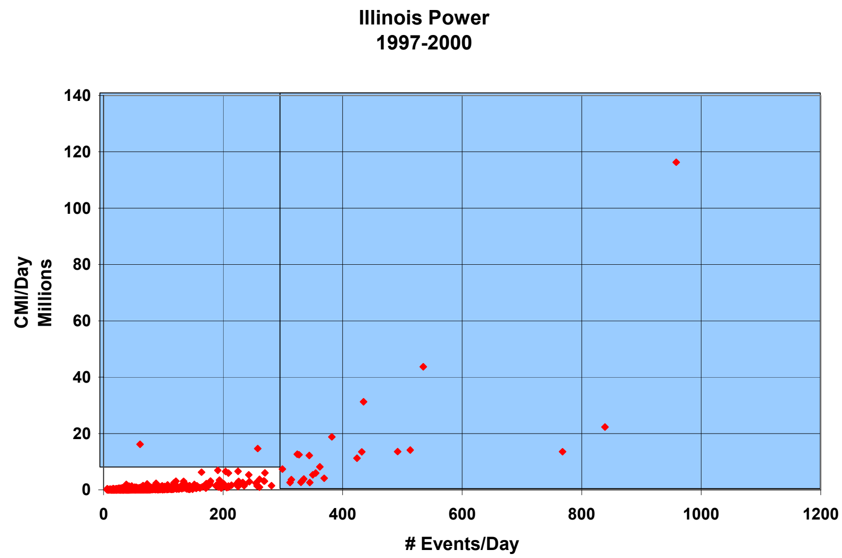
Table 22 shows Company performance from 1998 to 2000. 1998 was a particularly harsh weather year, while 1999 was particularly mild and 2000 was a relatively normal year. The weather differences are clearly seen in Table 22.

• Table 22. Exhibit 411.120.b.3.H Indices

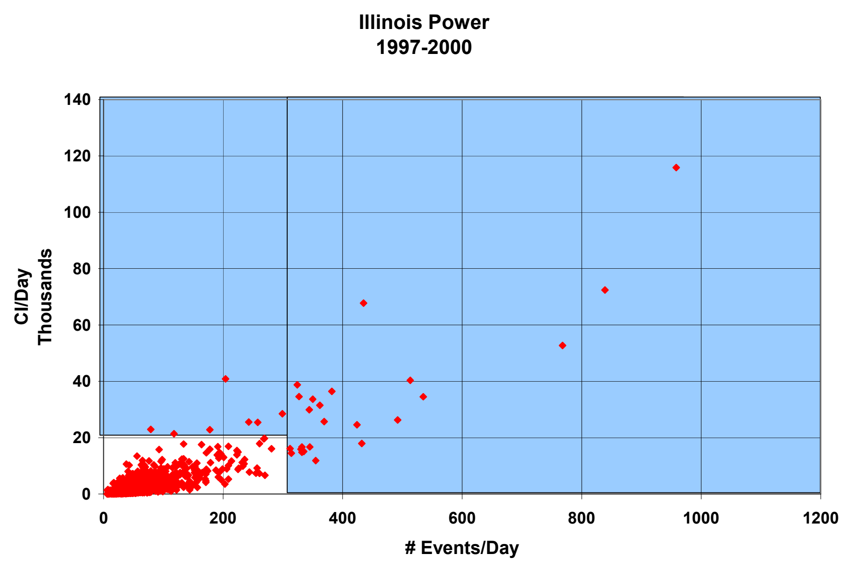
Year	SAIFI	CAIDI	CAIFI
2000	1.65	168	2.47
1999	1.35	144	1.96
1998	2.44	267	2.96

The IEEE Working Group on System Design is investigating new methods for determining "abnormal events". These are defined as events that exceed system design limits or normal operating conditions. The working group intends to create a methodology that will not allow system degradation issues to be disguised as storm related events. The objective is to create plots such as those shown in Figure 18 and Figure 19. Using these figures, abnormal days will be identified and explained. As part of the identification process, weather will be described as well as operating conditions at the time of events. If an abnormal event is within the control of the utility, for example a transmission event, then the utility will be encouraged to write a report explaining the event for submission to their regulator.

Four years of data are captured in Figure 18 and Figure 19 and are defined by 1461 points (365 days times 4 years plus one leap day). The abnormal criterion for IP is any day that has over 300 events or over 15,000,000 customer minutes interrupted or over 20,000 customers interrupted. There are 32 events (i.e., two percent of the population) that meet the criteria and are therefore considered to be abnormal events. The abnormal events are the dots shown in the blue background.



• Figure 18. Abnormal Events based on CMI



• Figure 19. Abnormal Events based on CI

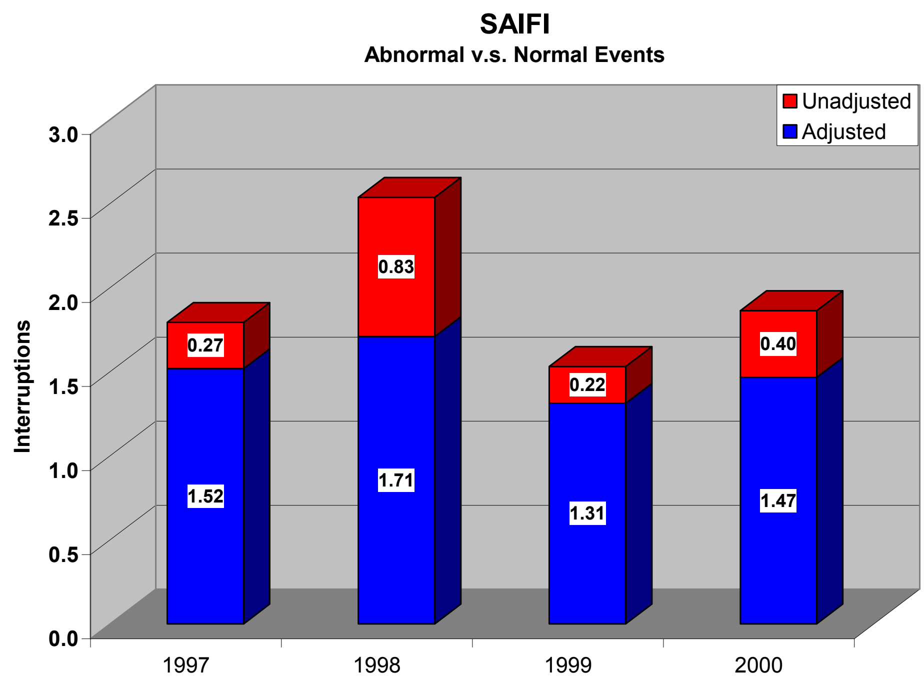
The days that are listed as abnormal events are shown in Table 23. The shaded days represent days that the Energy Delivery Emergency Response Organization ("EDERO") was activated. No information was available about EDERO days in 1997 or about unshaded days.

• Table 23. Abnormal Days

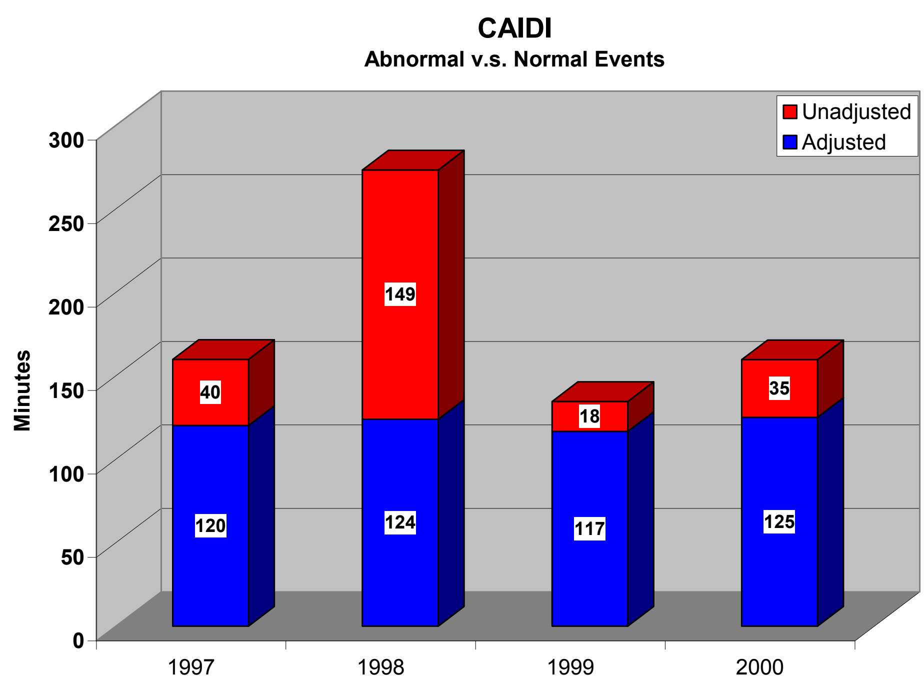
Abnormal Days

2/18/00	1/2/99	1/7/98	6/19/98	4/6/97
4/20/00	1/13/99	3/9/98	6/29/98	4/30/97
6/14/00	2/11/99	3/27/98	6/30/98	6/21/97
8/14/00	6/4/99	5/22/98	7/1/98	9/29/97
8/17/00	6/11/99	6/12/98	7/22/98	10/26/97
8/18/00		6/14/98	11/10/98	10/27/97
12/11/00		6/18/98	12/6/98	

Using the *proposed* IEEE abnormal approach and considering 1997-2000, Figure 20 and Figure 21 show normalized indices considering abnormal events. Notice that "normal" performance is fairly constant.



• Figure 20. SAIFI - Abnormal vs. Normal Events



• Figure 21. CAIDI Abnormal vs. Normal

l) A list showing the worst-performing circuits for each operating area for the annual reporting period with the understanding that the designation of circuits as "worst-performing circuits" shall not, in and of itself, indicate a violation of this Part.

The identification of IPs worst performing circuits ("WPC") has been a functional responsibility of the central staff group within the Energy Delivery department. However, the development of important root cause analysis, the associated remedial plans, and important follow up reporting of completed work, and associated costs for those WPCs has historically been the responsibility of local Area field management. The local Area focus resulted in utilization of mitigation techniques ranging from installation of animal and lightning protection equipment to complete rebuilding of facilitates to improve similar poor reliability condition situations. In order to heighten the focus on analysis, remedial alternative development and reporting of completed work, a formal reliability management group within the Energy Delivery department has been established; the Reliability group. This group will provide overall coordination necessary to ensure appropriate actions are being taken to effectively address customer reliability concerns, improve system reliability performance while at the same time making the most effective use of Company resources.

2000 Worst Performing Circuit Identification and Performance

Table 24 shows the worst performing circuits for 2000. The bolded values represent the indices that caused the circuit to be a worst performer.

• Table 24. Exhibit 411.120.b.3.I - Full List

Area Name	Area	Circuit	SAIFI	CAIDI	CAIFI
LaSalle	13	511	**5.62**	157	**5.85**
Bloomington	31	211	**4.54**	362	**4.67**
Bloomington	31	215	**4.58**	431	**4.69**
Bloomington	31	217	1.50	**1054**	1.62
Belleville	51	101	0.88	**890**	1.00
Belleville	51	105	1.17	**1731**	1.24
Belleville	51	111	**4.04**	295	**4.33**
Belleville	51	114	0.04	**1618**	1.00
Belleville	51	163	**4.87**	224	**5.07**
Belleville	51	253	0.73	**924**	1.00
Maryville	54	360	**9.25**	283	**9.36**
Maryville	54	362	1.61	**903**	2.12
Maryville*	54	368	**5.02**	281	**5.38**
Maryville	54	407	**4.39**	255	**4.63**
Granite City	64	298	1.10	**1338**	1.17
Granite City	64	322	0.05	**1084**	1.00
Granite City	64	334	0.38	**1169**	1.00
Mt Vernon	72	140	**5.43**	165	**5.74**

*Maryville 368 was a worst performing circuit in 1998.

Table 25 to Table 27 show the worst performing circuits segmented by index with performance shown from 1998 to 2000. It is obvious that some circuits are truly poor performers over time. Examples of these circuits include Maryville circuit 360 and circuit 368. Other circuits have the WPC designation stemming from one or more weather events. Examples of these circuits are Mt. Vernon circuit 140 and Belleville circuit 253. IP takes different approaches to remediation depending on the reasons each circuit earns the designation of WPC.

• Table 25. Exhibit 411.120.b.3.I - SAIFI 98-00

Area Name	Area	Circuit	2000	1999	1998
Maryville	54	360	9.25	0.72	4.55
LaSalle	13	511	5.62	2.47	2.35
Mt Vernon	72	140	5.43	1.93	1.11
Maryville	54	368	5.02	0.38	6.23
Belleville	51	163	4.87	1.77	2.50
Bloomington	31	215	4.58	0.47	6.20
Bloomington	31	211	4.54	2.75	4.02
Maryville	54	407	4.39	0.08	2.39
Belleville	51	111	4.04	0.55	2.50

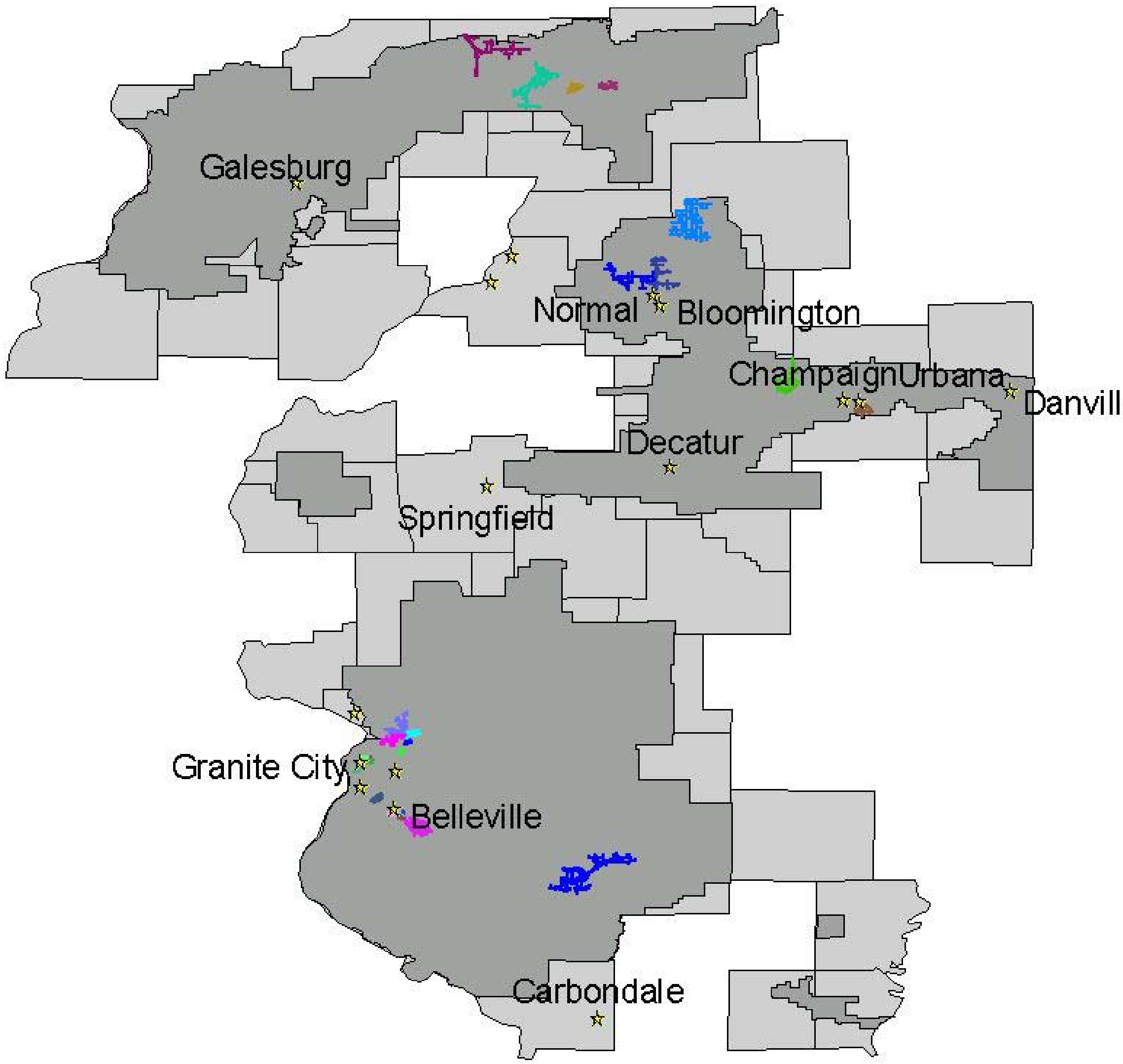
• Table 26. Exhibit 411.120.b.3.I CAIDI 98-00

Area Name	Area	Circuit	2000	1999	1998
Belleville	51	105	1731	48	171
Belleville	51	114	1618	318	268
Granite City	64	298	1338	62	281
Granite City	64	334	1169	163	184
Granite City	64	322	1084	123	189
Bloomington	31	217	1054	282	247
Belleville	51	253	924	139	193
Maryville	54	362	903	131	548
Belleville	51	101	890	3	468

• Table 27. Exhibit 411.120.b.3.I CAIFI 98-00

Area Name	Area	Circuit	2000	1999	1998
Maryville	54	360	9.36	1.53	4.38
LaSalle	13	511	5.85	2.41	2.27
Mt Vernon	72	140	5.74	2.22	1.48
Maryville	54	368	5.38	2.12	6.07
Belleville	51	163	5.07	1.81	2.77
Bloomington	31	215	4.69	2.09	5.88
Bloomington	31	211	4.67	2.74	3.90
Maryville	54	407	4.63	1.00	2.33
Belleville	51	111	4.33	2.04	2.38

Figure 22 shows a high level view of the 2000 worst performing circuit locations. Each colored line represents one of the worst performing circuits.



• Figure 22. WPC Locations

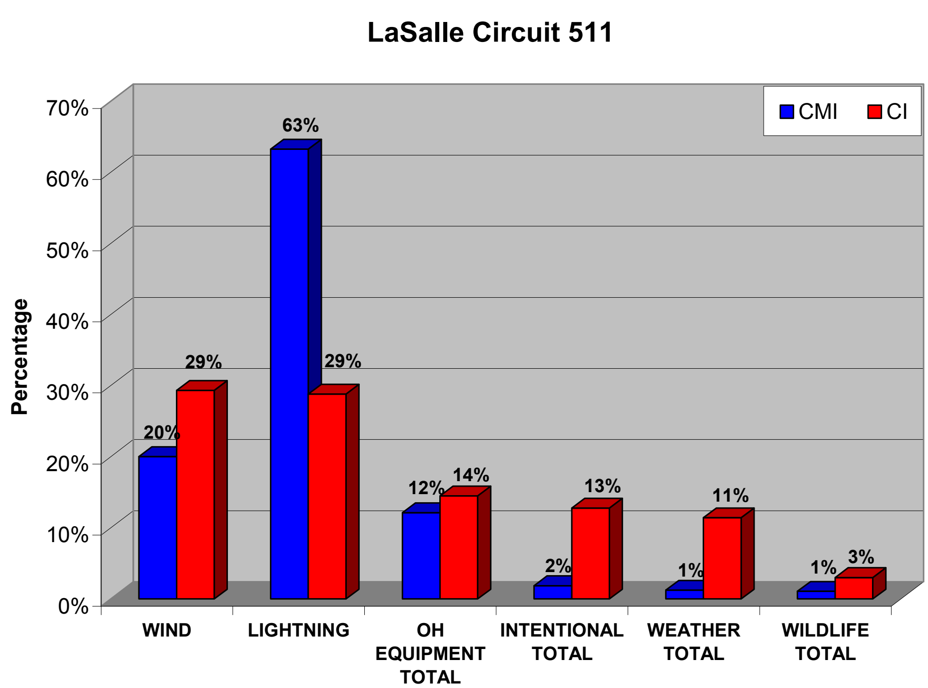
J) *A statement of the operating and maintenance history of circuits designated as worst-performing circuits; a description of any action taken or planned to improve the performance of any such circuit (which shall include information concerning the cost of such action); and a schedule for completion of any such action. (The jurisdictional entity may decide, based on cost considerations or other factors, that it should take no action to improve the performance of one or more circuits designated as worst-performing circuits. If the jurisdictional entity decides to take no action to improve the performance of one or more circuits designated as worst-performing circuits, the jurisdictional entity shall explain its decision in its annual report.)*

2000 Worst Performing Circuits

The following sections discuss remediation of circuits that were designated as worst performers in 2000. Some were truly worst performers, while others made the list due a single event.

LaSalle Circuit 511 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 1583 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 23 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind and Lightning were the predominant cause of high CI and CMI.

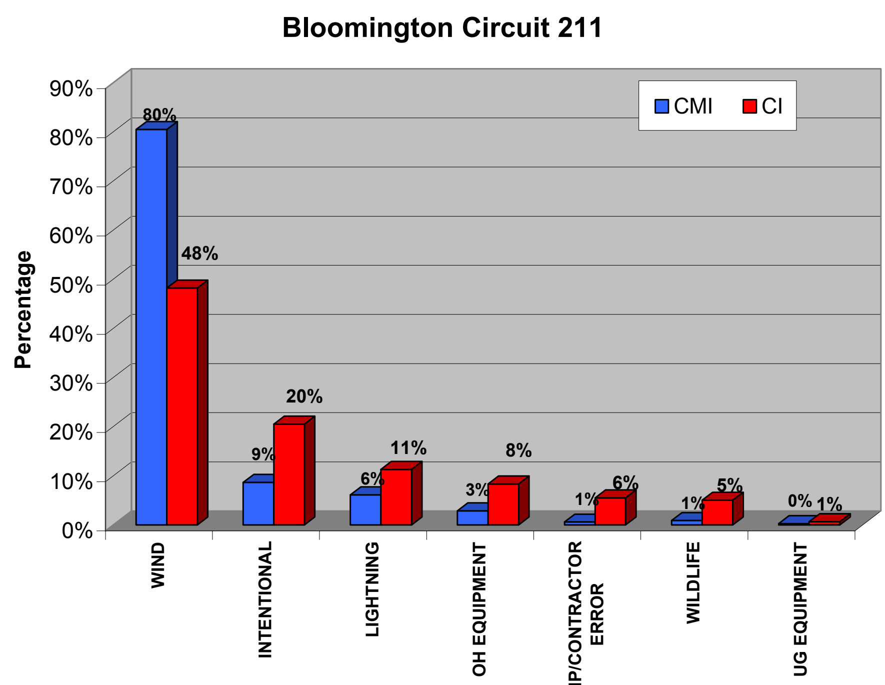


• Figure 23. LaSalle Circuit 511 Causes of 2000 Interruptions

This circuit was patrolled in both 1999 and in 2001. It was trimmed in 1998 at a cost of $128,771 in *constant 1998 dollars*. There is no indication of tree related issues and this circuit will be trimmed in 2002. This circuit was patrolled in 2001 and forty potential mitigation items were identified. Twenty to twenty-five fuses are being added at a cost of $9,005 in *constant 1998 dollars.* The additional fuses should reduce the impact of interruptions.

Bloomington Circuit 211 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 920 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 23 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.

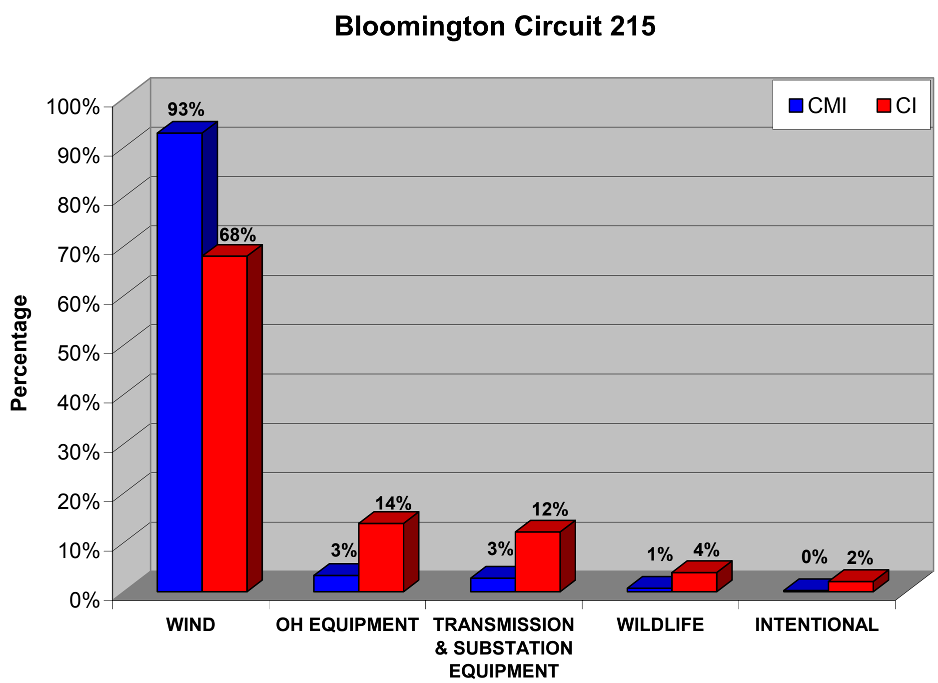


• Figure 24. Bloomington Circuit 211 - Causes of 2000 Interruptions

This circuit was patrolled in both 1998 and in 2001. It was trimmed in February 2001 at a cost of $42,603 in *constant 1998 dollars*. This recent trim may reduce the number of wind related issues that this circuit experiences in 2001. Approximately fifteen to twenty fuses are being installed at a cost of $23,679 in *constant 1998 dollars*. Approximately two hundred and four animal guards are being installed at a cost of $15,166 in *constant 1998 dollars*. One hundred and seventy-seven items were identified on the maintenance patrol as possible repair opportunities. A planning and coordination study is being performed on this circuit and will be complete by December 2001. Findings from this study will be implemented by June 2002.

Bloomington Circuit 215 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 807 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 25 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.

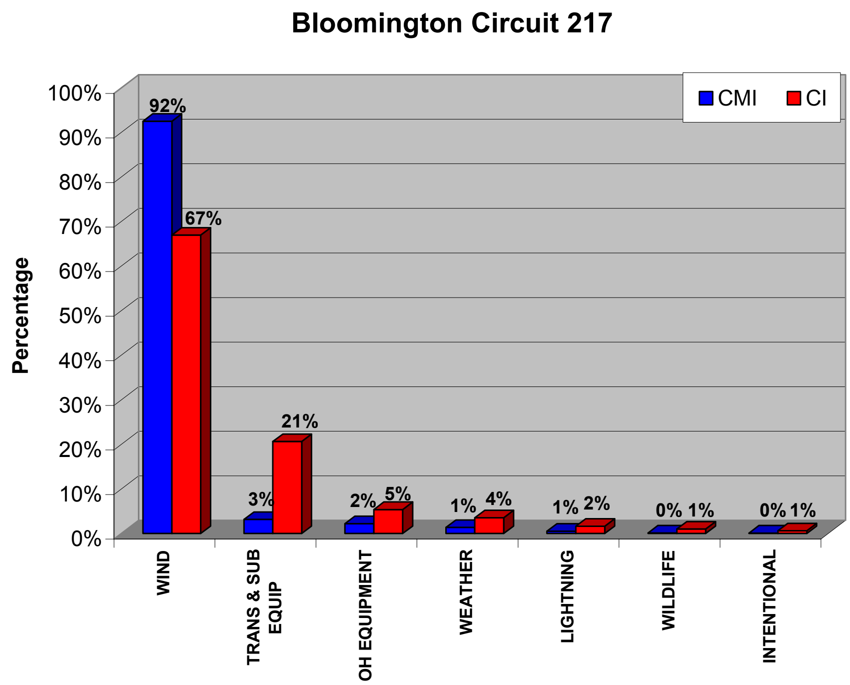


• Figure 25. Bloomington Circuit 215 - Causes of 2000 Interruptions

This circuit was patrolled in both 1998 and in 2001. It was trimmed in April 1998 at a cost of $39,163 in *constant 1998 dollars*. One hundred and seventy three animal guards are being installed on this circuit at a cost of $13,271 in *constant 1998 dollars.* Twenty-six additional items were identified during the maintenance patrol as potential repair opportunities.

Bloomington Circuit 217 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 414 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 26 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.

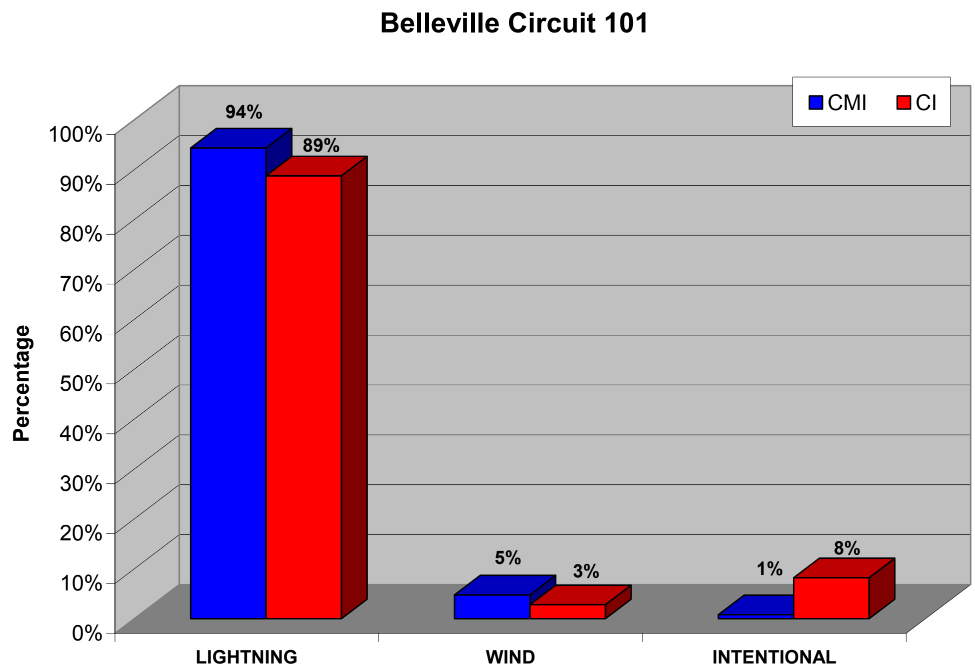


• Figure 26. Bloomington Circuit 217 - Causes of 2000 Interruptions

This circuit was patrolled in both 1998 and in 2001. It was trimmed in May 1998 at a cost of $18,591 in *constant 1998 dollars*. Approximately twenty-four fuses will be installed on this circuit at a cost of $9,479 in *constant 1998 dollars*. Approximately one hundred and forty six animal guards will be installed on this circuit at a cost of $11,375 in *constant 1998 dollars*. Two hundred and ninety three items were identified during the maintenance patrol as potential repair opportunities.

Belleville Circuit 101 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 248 customers at 4.16 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 27 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Lightning was the predominant cause of high CI and CMI.

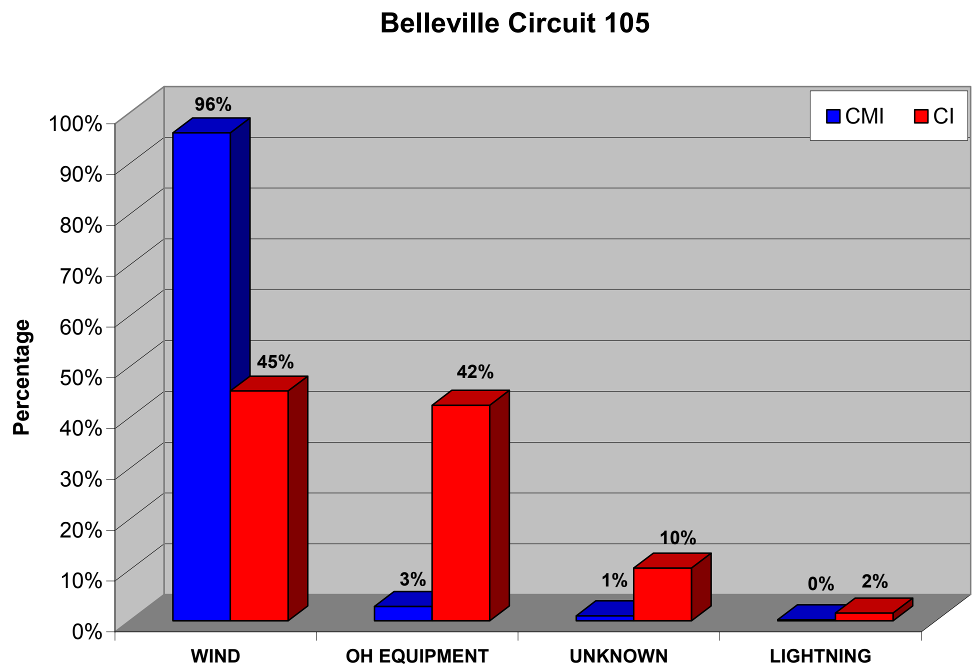


• Figure 27. Belleville Circuit 101- Causes of 2000 Interruptions

This circuit was patrolled in both 2000 and in 2001. It was trimmed in December 1997. The local Area will perform a lightning analysis of the circuit and will implement recommendations from the analysis by June 2002.

Belleville Circuit 105 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 398 customers at 4.16 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 28 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Lightning was the predominant cause of high CI and CMI.

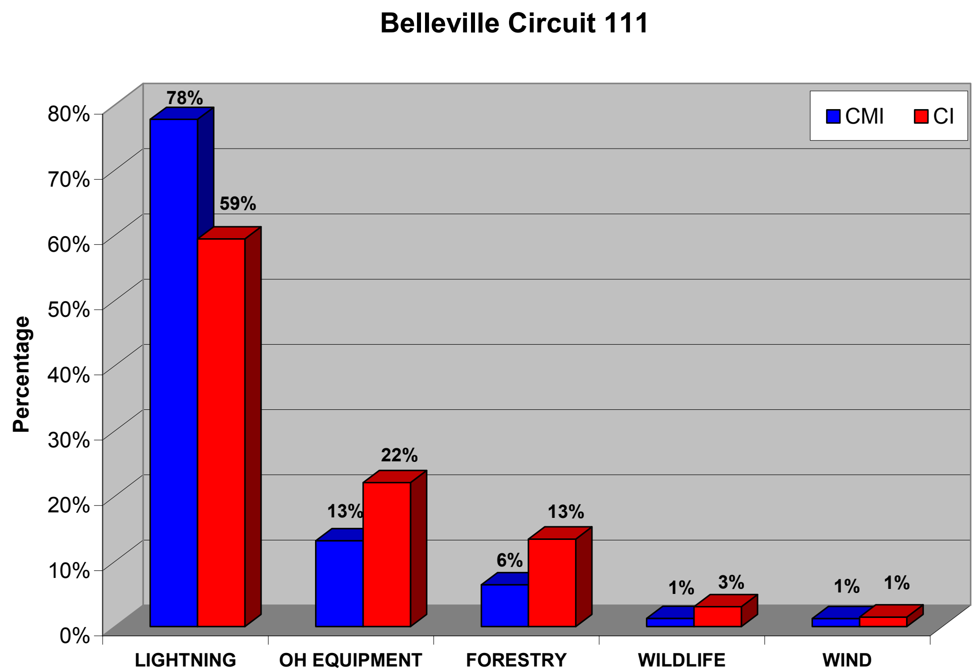


• Figure 28. Belleville Circuit 105- Causes of 2000 Interruptions

This circuit was patrolled in both 2000 and in 2001. It was trimmed in November 1997. Thirty-one repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items.

Belleville Circuit 111 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 675 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 29 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Lightning was the predominant cause with overhead equipment failure as the second largest cause of high CI and CMI. Many times overhead failures are directly related to lightning activity.

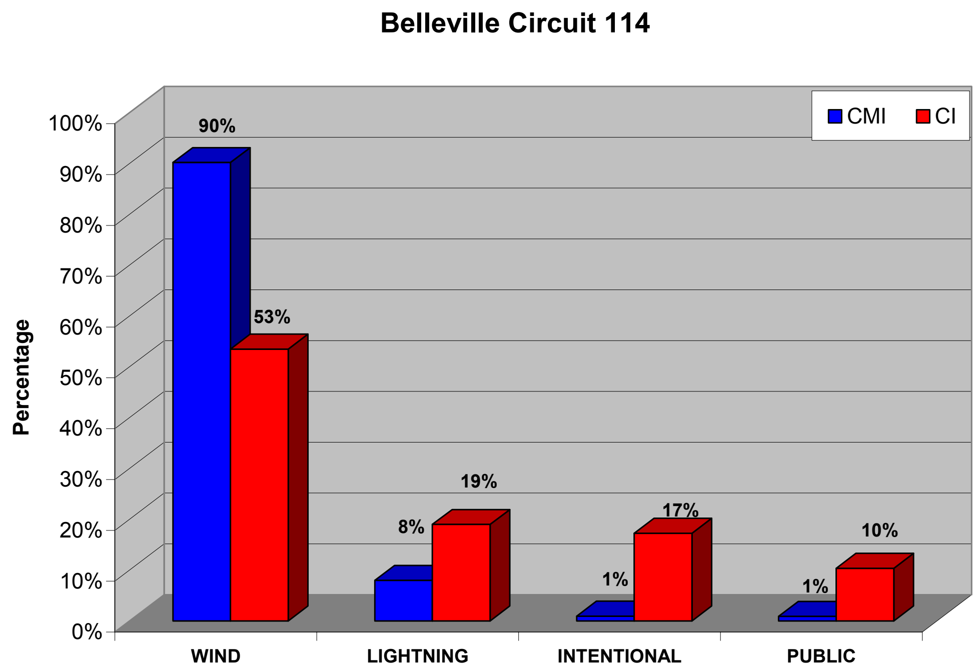


• Figure 29. Belleville Circuit 111 - Causes of 2000 Interruptions

This circuit was patrolled in both 2000 and in 2001. It was trimmed in May 1998 at a cost of $ 59,660 in *constant 1998 dollars*. Ninety-eight potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. In addition, two reclosers and fifteen to twenty fuses will be installed at key locations at a cost of $34,124 in *constant 1998 dollars*. A planning and coordination study is currently on-going and will be completed by December 2001 with recommendations being implemented b y June 2002.

Belleville Circuit 114 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 314 customers at 4.16 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 30 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.

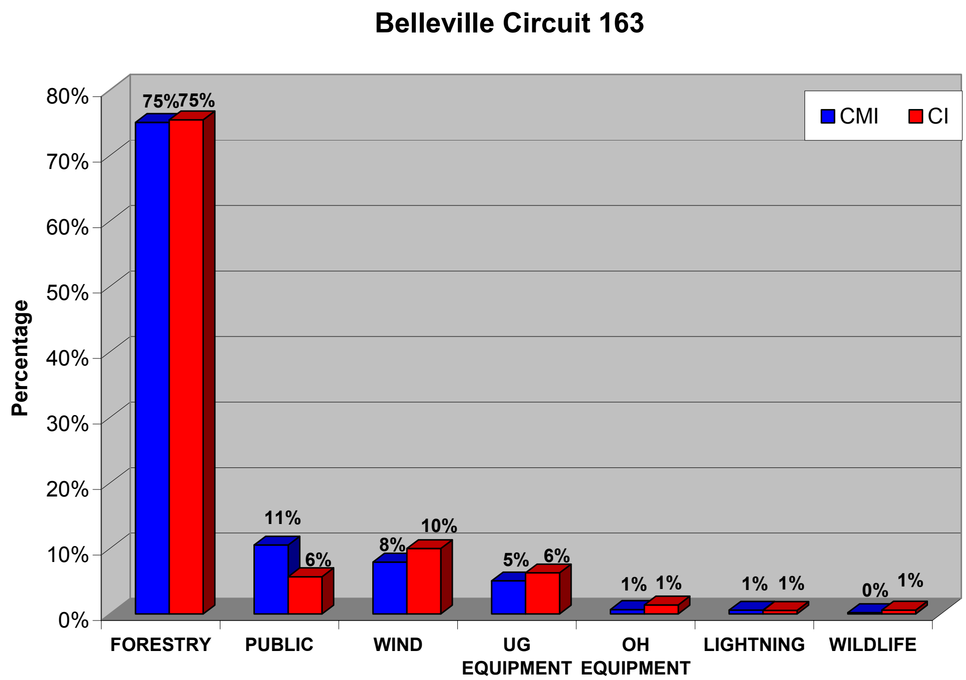


• Figure 30. Belleville Circuit 114 - Causes of 2000 Interruptions

This circuit was patrolled in both 1997 and in 2001. It was trimmed in March 1998 at a cost of $ 133,832 in *constant 1998 dollars*. Thirteen potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. No additional action is being taken on this circuit.

Belleville Circuit 163 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 734 customers at 12.47 kV and is 80% overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 31 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Forestry was the predominant cause of high CI and CMI.

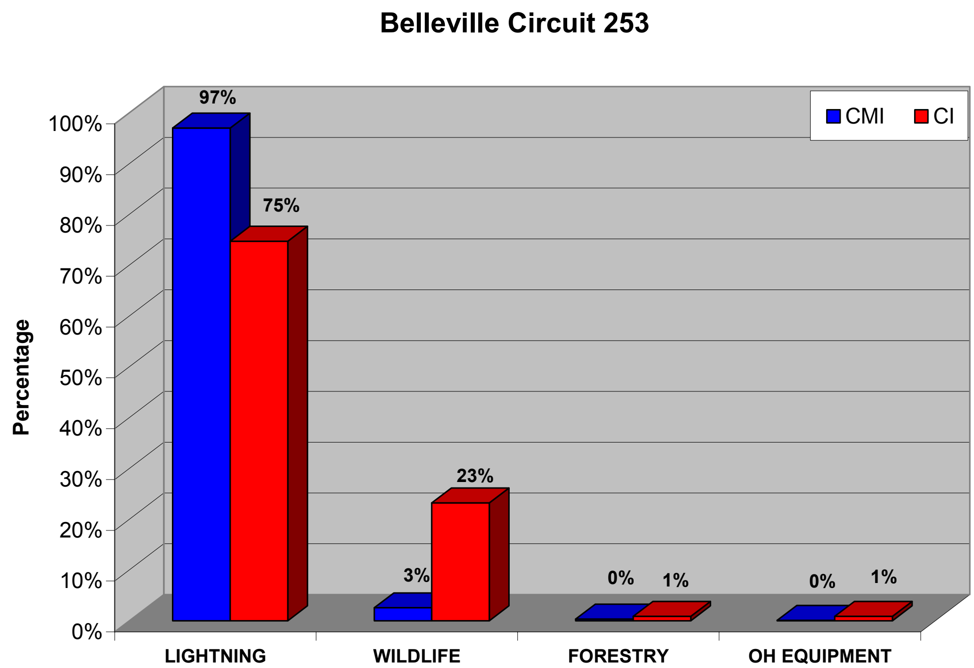


• Figure 31. Belleville Circuit 163 - Causes of 2000 Interruptions

This circuit was patrolled in both 1997 and in 2001. This circuit was trimmed in September 1996 and will be trimmed in 2001. Two hundred and ninety one potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. Additionally, three-phase fuses will be replaced with reclosers and fifteen to twenty new fuses will be installed at a cost of $22,749 in *constant 1998 dollars* to reduce exposure.

Belleville Circuit 253 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 292 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 32 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Lightning was the predominant cause of high CI and CMI.

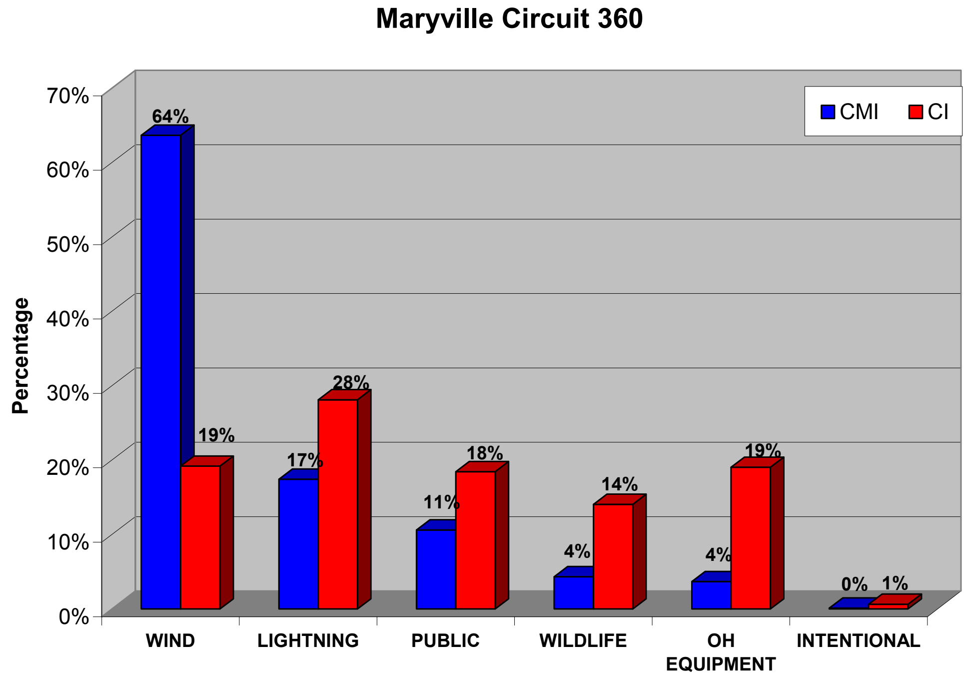


• Figure 32. Belleville Circuit 253 - Causes of 2000 Interruptions

This circuit was patrolled in both 1999 and in 2001. This circuit was trimmed in September 1997. One hundred and forty five potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. The remediation plans will be completed by June 1, 2001.

Maryville Circuit 360 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 1399 customers at 12.47 kV and is 92% overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 33 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind and lightning were the top causes of high CI and CMI.

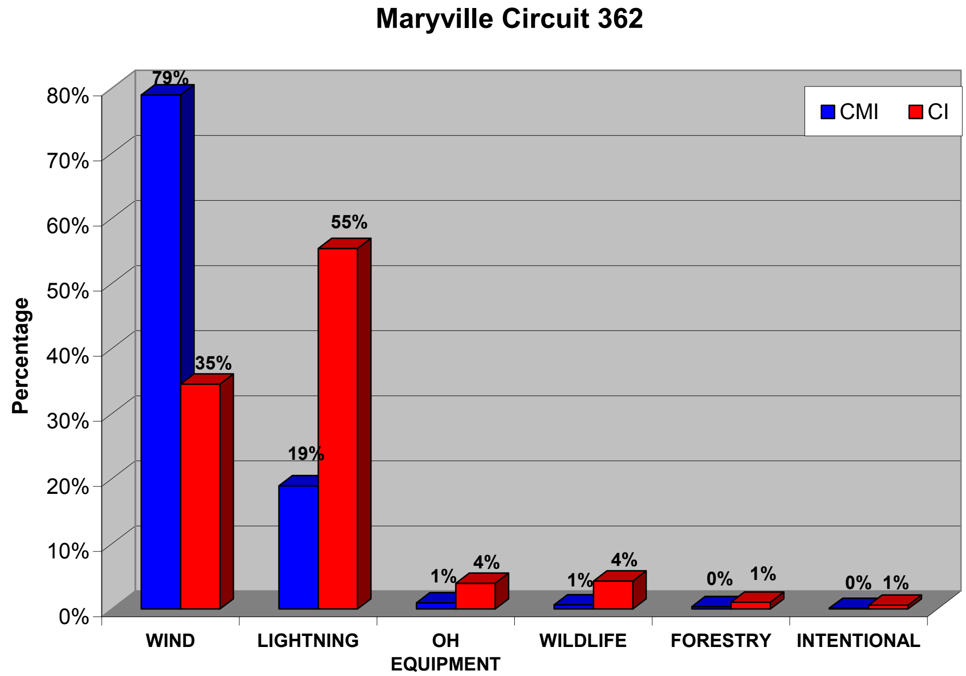


• Figure 33. Maryville Circuit 360 - Causes of 2000 Interruptions

This circuit was patrolled in 2000 and 2001. This circuit was trimmed in June 2000 at a cost of $190,515 in *constant 1998 dollars*. Fuses and animal guards will be installed at three hundred plus transformer locations at a cost of $26,067 in *constant 1998 dollars*. One hundred and twenty seven potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. The remediation plans will be completed by June 1, 2001. A planning and coordination study is currently on-going and will be complete by December 2001 with recommendations implemented by June 2002.

Maryville Circuit 362 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 1261 customers at 12.47 kV and is 94% overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 34 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind and lightning were the predominant cause of high CI and CMI.

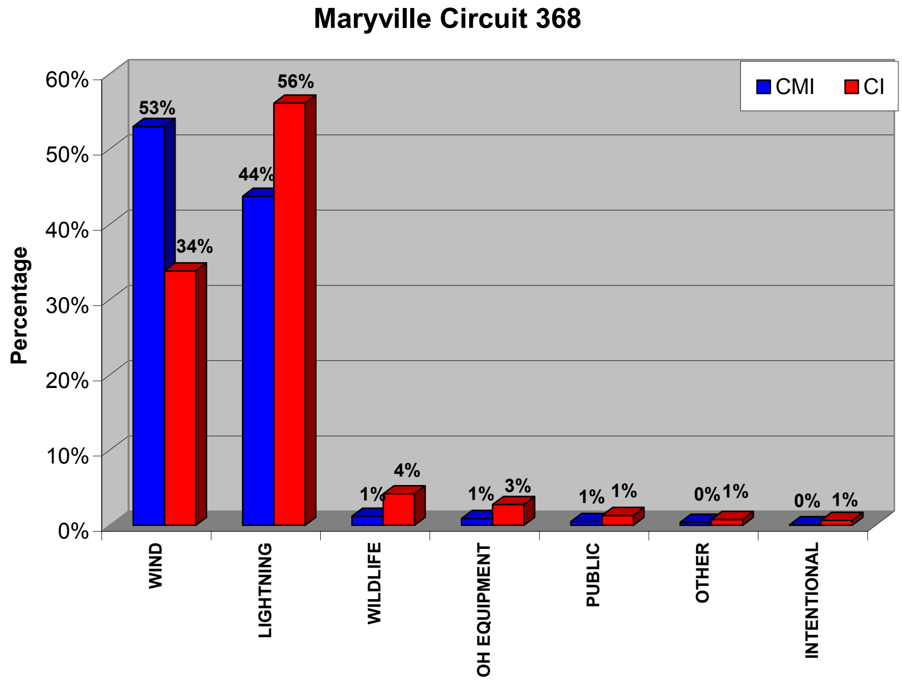


• Figure 34. Maryville Circuit 362 - Causes of 2000 Interruptions

This circuit will be patrolled by June 2001. This circuit will be trimmed in March 2001. Three additional fuses will be installed and one blown lighting arrester will be replaced at a cost of $1,723 in *constant 1998 dollars*. The remediation plans will be completed by June 1, 2001. A planning and coordination study is currently on-going and will be complete by December 2001 and recommendations will be implemented by June 2002.

Maryville Circuit 368 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 783 customers at 12.47 kV and is 80% overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 35 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind and lightning were the predominant cause of high CI and CMI.



• Figure 35. Maryville Circuit 368 - Causes of 2000 Interruptions

This circuit was trimmed in December 1998 at a cost of $78,681. Two sets of additional fuses will be installed at a cost of $1,422 in *constant 1998 dollars*. This circuit was patrolled in 2000 and 2001. In 1999, projects were performed to replace:

- a bad pole and cross arm and
- disconnects with 600 Amp "underslung" blades

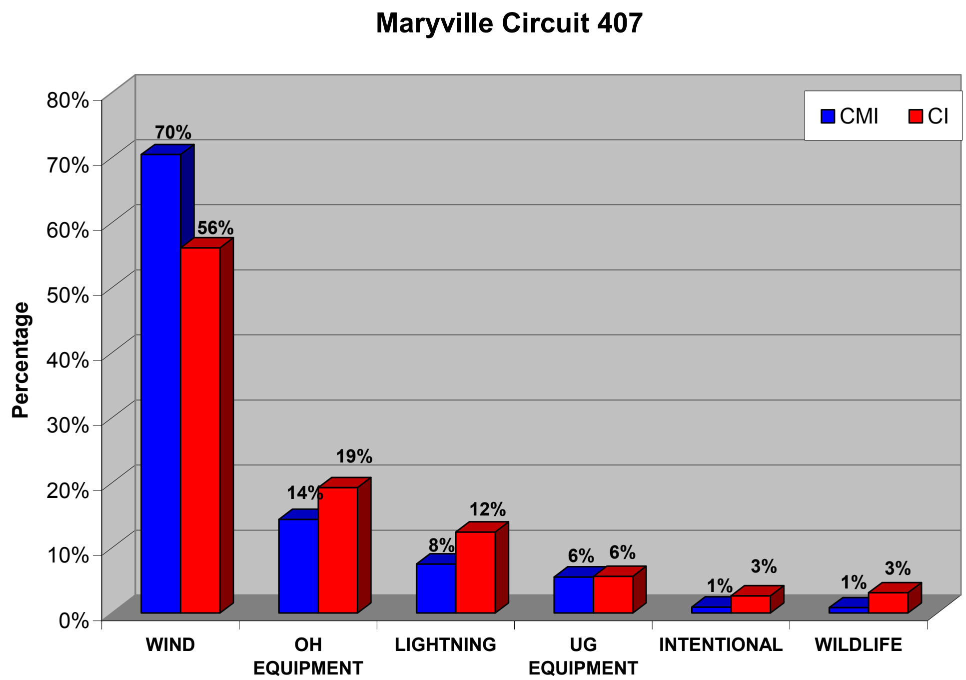
at a cost of $1,043 in constant 1998 dollars. During 2000, several projects were performed:

- Rebuilt two spans of 1/0 spacer cable to open wire and replaced one pole,
- Replaced nine poles
- Repaired twenty-eight maintenance items, and
- Removed unused dead blades

at a cost of $27,320 in *constant 1998 dollars*.

Maryville Circuit 407 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 1118 customers at 12.47 kV and is 84% overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 36 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.



• Figure 36. Maryville Circuit 407 - Causes of 2000 Interruptions

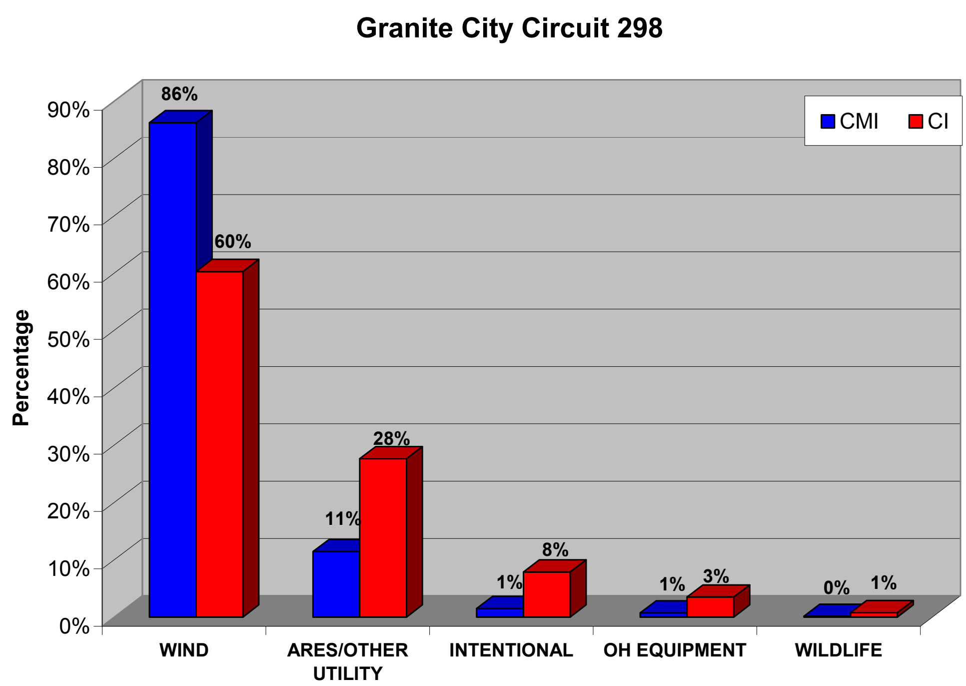
This circuit was trimmed in March 2001. During 2000, failed underground primary was replaced and a set of reclosers was upgraded at a cost of $6,645 in *constant 1998 dollars*. The circuit was patrolled in 1997 and 2001. Seventy-seven potential repair items were identified during the 2001 patrol and work plans have been submitted to remediate the high priority items. During 2001, the following projects were completed:

- Replaced a pole,
- Replaced discs with 400 amp underslung blades, and
- Repaired twenty-five maintenance items

at a cost of $10,900 in *constant 1998 dollars*.

Granite City Circuit 298 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 273 customers at 4.16 kV and is all overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 37 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind was the predominant cause of high CI and CMI.

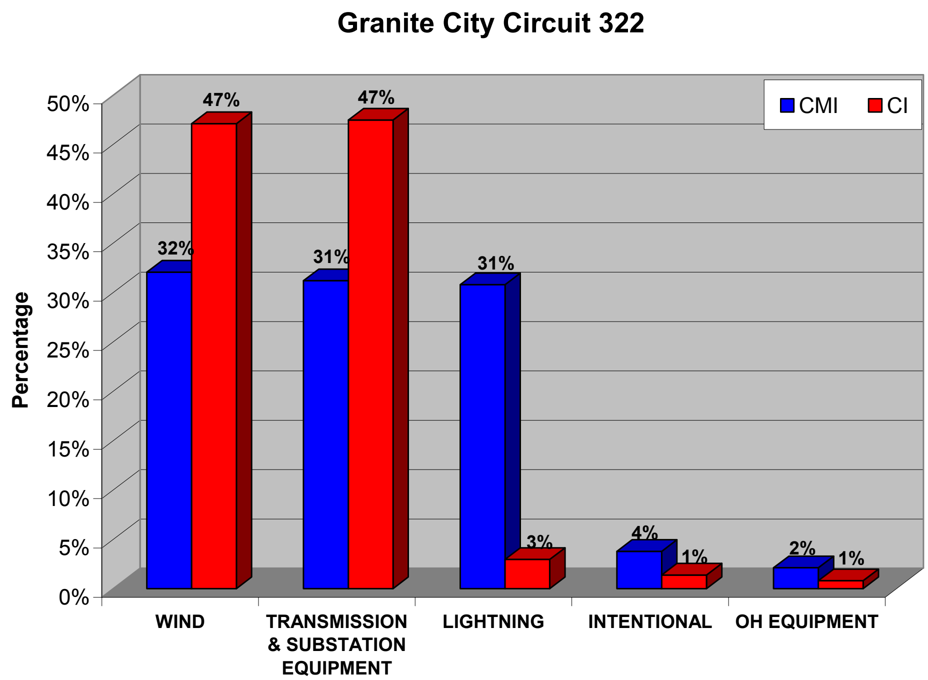


• Figure 37. Granite City Circuit 298 - Causes of 2000 Interruptions

This circuit was patrolled in 2000 and four bad poles were replaced at a cost of $6,170 in *constant 1998 dollars*. The circuit made the WPC list due to a storm. This circuit was trimmed in April 1999 at a cost of $14,109 in *constant 1998 dollars*. Remediation plans will be completed by June 1, 2001.

Granite City Circuit 322 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 676 customers at 4.16 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as urban. Figure 38 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Wind, transmission and substation equipment, and lightning were the predominant cause of high CI and CMI.

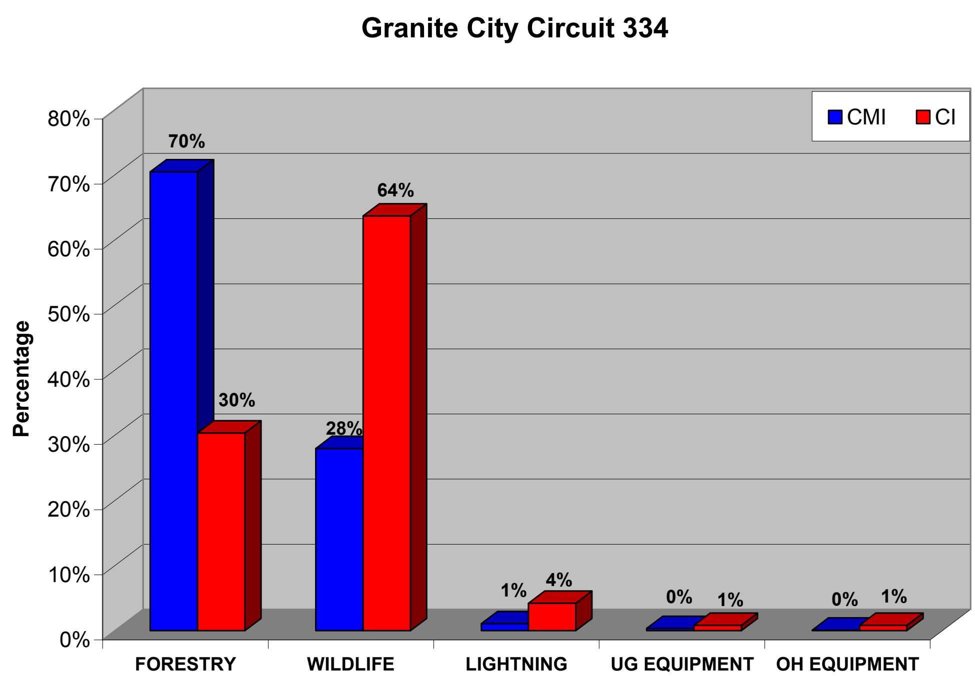


• Figure 38. Granite City Circuit 322 - Causes of 2000 Interruptions

This circuit will be patrolled by June 2001. Reliability analysis was performed and no additional action is required. This circuit was trimmed in November 1997.

Granite City Circuit 334 – 2000 WPC

This circuit was a worst performer from a CAIDI perspective. It serves 165 customers at 12.47 kV and is 93% overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 39 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Forestry and wildlife were the predominant cause of high CI and CMI. This circuit was trimmed in October 1997 and is scheduled to be trimmed again in 2001.

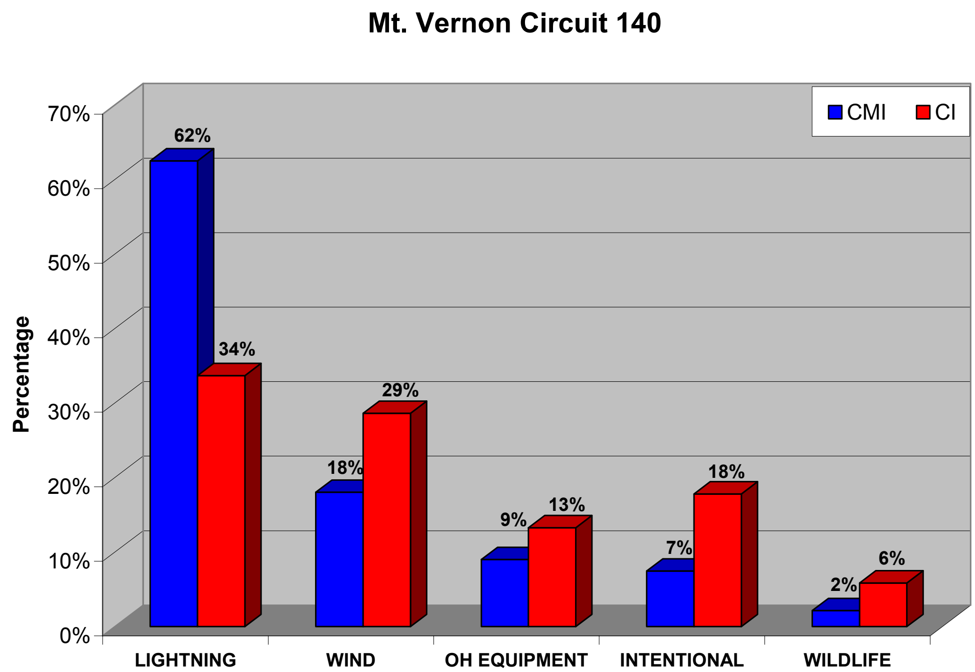


• Figure 39. Granite City Circuit 334 - Causes of 2000 Interruptions

This circuit was patrolled in 1999. It was trimmed in October 1997. Two new sets of fuses will be installed at an estimated cost of $1,137 in *constant 1998 dollars*.

Mount Vernon Circuit 140 – 2000 WPC

This circuit was a worst performer from both a SAIFI and CAIFI perspective. It serves 891 customers at 12.47 kV and is mostly overhead. Based on the customer density per circuit mile, the circuit is classified as rural. Figure 40 shows the percentage of customers interrupted and customer minutes interrupted by cause category for 2000. Lightning and wind were the predominant cause of high CI and CMI.



• Figure 40. Mt. Vernon Circuit 140 - Causes of 2000 Interruptions

This circuit was patrolled in 2000 and 2001. This circuit was trimmed in March 1998 at a cost of $146,544. During 1999, thirty bad poles were replaced and a section of spacer cable was repaired at a cost of $86,000. During 1999, several poles were replaced, two reclosers were upgraded, and one station was removed to reduce exposure at a cost of $70,038 in *constant 1998 dollars*.

1998 Worst Performing Circuit Remediation

Table 28 shows the 1998 worst performing circuits with their subsequent 1999 and 2000 performance.

• Table 28. 1998 Worst Performing Circuits with Subsequent Performance

1998 Worst Performing Circuits			1998 Performance			1999 Performance			2000 Performance		
Area Name	Area	Circuit	SAIFI	CAIDI	CAIFI	SAIFI	CAIDI	CAIFI	SAIFI	CAIDI	CAIFI
Belleville	51	269	6.12	314	**5.93**	3.26	234	3.13	0.31	120	1.22
Bloomington	31	246	1.29	**2,626**	1.24	0.33	213	1.68	0.41	84	1.67
Bloomington	31	342	**7.54**	265	**7.38**	0.59	340	1.01	1.17	72	2.20
Bloomington	31	402	**7.82**	466	**6.15**	1.37	66	1.46	0.72	87	1.41
Decatur	35	115	**6.62**	342	5.76	2.30	115	2.05	2.79	62	3.02
Galesburg	11	112	1.39	**2,362**	1.38	0.19	117	1.11	0.14	58	1.16
Galesburg	11	113	2.6	**2,109**	2.59	0.09	69	1.00	0.09	61	1.00
Galesburg	11	115	1.8	**2,674**	1.76	2.11	37	2.09	0.03	131	1.00
Galesburg	11	117	**6.82**	567	**6.41**	0.56	252	1.01	0.06	217	1.00
Galesburg	11	122	1.16	**3,860**	1.08	0.05	320	1.00	0.00	0	0.00
Galesburg	11	124	1.13	**4,124**	1.05	0.00	0	0.00	0.00	0	0.00
Galesburg	11	125	1.23	**4,855**	1.17	0.03	106	1.00	0.00	0	0.00
Galesburg	11	144	**7.67**	802	**6.94**	1.00	154	1.68	0.60	147	1.84
Galesburg	11	171	2.76	**1,908**	2.28	1.61	128	1.51	0.58	161	1.83
Galesburg	11	175	**7.22**	668	**6.75**	0.14	108	1.00	0.26	132	1.05
Galesburg	11	185	0.45	**1,928**	1.34	0.06	164	1.00	0.20	95	1.29
Maryville	54	368	**6.23**	245	**6.07**	0.38	167	2.12	5.02	281	5.38
Sparta	73	935	**7.82**	117	**7.52**	1.23	672	1.26	0.03	192	1.27
Mt. Vernon	72	131	**6.45**	339	**6.17**	2.45	210	2.35	1.53	301	1.61

Belleville 269 – WPC 1998

Belleville Circuit 269 was patrolled in 1999 and rebuild work was performed at a cost of $22,749 (*in constant 1998 dollars*). No further action was required.

Bloomington 246 – WPC 1998

Bloomington Circuit 246 has historically been a reliable circuit. The poor performance shown in 1998 was the direct result of the abnormal weather event on 6/29-30. Had abnormal events been used to exclude events, this circuit would not have made the worst performing circuits list. During the event, fifty poles were replaced at a cost of $80,000. Inspection of the circuit in 1999 resulted in rebalancing it and replacing a CSP transformer with a conventional bank at a cost of $6,920 in *constant 1998 dollars*.

Bloomington 342 – WPC 1998

The predominate causes of interruption in 1998, as judged by CI and CMI, were wind and overhead equipment failure. Various pieces of overhead equipment failed that year with the two largest components being a conductor and a pole event. Since that time, the Area replaced some old porcelain disconnect switches, sections of underground cable that had failed numerous times, installed new reclosers, added elbow lightning arresters, changed opens in UG loops, and re-fused primary risers. This work was accomplished for $11,375 in *constant 1998 dollars*.

Bloomington 402 – WPC 1998

This circuit was patrolled in 1999 after it was identified as a worst performing circuit in 1998. Reviewing the causes of interruptions in 1998, it is clear that this circuit became a worst performing circuit due to lightning and overhead equipment failure. The three biggest events in 1998 came within a week of one another. First, the circuit was struck by lightning and then a week later the conductor failed, a jumper went, and a transformer failed. Since 1998, this circuit may not have seen much action from lightning in the susceptible area. The Area completed remedial work on this circuit consisting of (1) replacing a pole hit by a tractor-trailer truck, (2) some underground cable that had failed four times in less than 12 months, and (3) replacing a CSP with a conventional transformer. The cost of these projects was $18,579 in *constant 1998 dollars*.

Decatur 115 – WPC 1998

This circuit experienced two events during the abnormal weather event on June 29-30th that cause the circuit SAIFI to increase by 1. If those events had not occurred, this circuit would not have made the worst performing circuit list. However, there were other incidents that contributed to this circuit's addition to the WPC list. During 1998, there were five events that cause the SAIFI and CAIFI to increase by almost 1. They were (1) lightning during a weather event, (2) wind contacting the circuit, (3) trees contacting the circuit, (4) jumpers failing, and (5) other lightning events. A remedial plan was developed that resulted in replacing reclosers, rebuilding a portion of the three-phase main circuit, and replacing some underground cable and pad-mounted transformers. The cost for these projects was $18,010 in *constant 1998 dollars*.

Galesburg 112 and 113 – WPC 1998

The Galesburg area was hit particularly hard during the abnormal weather event on June 29-30th. If this event had not occurred, then most of the Galesburg circuits would not have made the worst performing circuits list. As a result, upon completion of emergency repairs, there was no additional reliability work required on these circuits.

The local Area monitored this and adjacent circuits and found that they were experiencing animal related outages due to animals in the substation. In 2000, the Seminary substation, which feeds these circuits, was animal proofed at a cost of $18,200 in *constant 1998 dollars*.

Galesburg 115 – WPC 1998

The Galesburg area was hit particularly hard during the abnormal weather event on June 29-30th. If this event had not occurred, then most of the Galesburg circuits, including this one, would not have made the worst performing circuits list.

The local Area monitored this and adjacent circuits and found that they were experiencing animal related outages due to animals in the substation. In 2000, the South Farnham substation, which feeds this circuit, had animal proofing performed for $18,200 in *constant 1998 dollars*.

Galesburg 117 – WPC 1998

The Galesburg area was hit particularly hard during the June 29-30th weather event. If this event had not occurred, then most of the Galesburg circuits would not have made the worst performing circuits list. This circuit is no exception.

Despite the fact that this circuit would not have been a worst performer were it not for the abnormal event, IP did perform work on this feeder. Projects were preformed during 1998 to correct for ADMs sensitive co-generation issues and to reclosers were added to eliminate faults on IPs circuit that were caused by faults internal to Butler manufacturing. These projects were performed at a cost of $10,339. A special set of high-fault duty reclosers will be installed in 2001 on the circuit to better isolate and coordinate it. This should reduce the number of faults experienced at the substation. The estimated cost of this project is $6,635 in *constant 1998 dollars*.

Galesburg 122,124, and 125 – WPC 1998

The Galesburg area experienced the brunt of the abnormal weather event on June 29-30th. If this event had not occurred, then Galesburg circuits 122, 124 and 125 would not have made the worst performing circuits list.

In 1999, the local Area continued to monitor these circuits and ultimately replaced and repaired Hendrix cable located outside the substation. This location is 4 kV buss regulated and faults on this section would affect circuits 122,124 and 125.

Galesburg 144 – WPC 1998

As previously noted, the Galesburg area experienced the brunt of the abnormal weather event on June 29-30th. While this circuit was affected by that event, it also had numerous other events that year resulting in significant CI and CMI.

Central Staff and the local Area worked together to produce a remedial plan for this circuit. In 1998, the animal and lightning protection on approximately ten miles of this circuit was upgraded at a cost of $12,000. In 1999, several planning projects were initiated that involved both Circuit 144 and Circuit 108. These projects reduced the exposure and total load on Circuit 144 and introduced a tie switch at node 037DW8. These projects cost $2,844 in *constant 1998 dollars*. In 2000, voltage regulators were installed at a cost of $10,427 in *constant 1998 dollars*.

Galesburg 171 – WPC 1998

As previously noted, the Galesburg area experienced the brunt of the abnormal weather event on June 29-30th. While this circuit was affected by that event, it also had numerous other events that year resulting in significant CI and CMI.

To reduce the lengthy duration of interruptions experienced on this circuit, in 2000, an outlying troubleman patrolled the circuit and installed faultfinders at a cost of $3,412 in *constant 1998 dollars*.

Galesburg 175 – WPC 1998

As previously noted, the Galesburg area experienced the brunt of the abnormal weather event on June 29-30th. While this circuit was affected by that event, it also had numerous other events that year resulting in significant CI and CMI.

An outlying troubleman patrolled the circuit and replaced lightning arresters in various locations at a cost of $4,266 in *constant 1998 dollars*. In 2000, a regulator bypass switch was replaced and new voltage regulators were installed at a cost of $8,105 in *constant 1998 dollars*.

Galesburg 185 – WPC 1998

The Galesburg area was hit particularly hard during the June 29-30th weather event. If this event had not occurred, then most of the Galesburg circuits would not have made the worst performing circuits list. While this circuit was affected by that event, it also had numerous other events that year resulting in significant CI and CMI.

In 1998 animal guards were installed at a cost of $2,370 in *constant 1998 dollars*. The Area is monitoring underground cable failures and will replace cable sections when they exceed company criteria for replacement as designated by the asset management process.

Maryville 368 – WPC 1998

This circuit was a worst performing circuit in 1998 and is again a worst performing 2000. The Area has performed numerous projects on this circuit. In 1999, a pole with disconnects and a crossarm was replaced for $2,844 and a set of 600A disconnects were replaced for $1,137 in *constant 1998 dollars*. The following list gives the 2000 projects:

- Two spans were rebuilt from1/0 spacer cable to open wire and a pole was replaced in the process at a cost of $5,885 in *constant 1998 dollars*,
- numerous poles were replaced and installed at a cost of $10,101 in *constant 1998 dollars*, and
- twenty eight maintenance items were repaired at a cost of $11,375 in *constant 1998 dollars*.

Sparta 935 – WPC 1998

This circuit suffered from numerous interruptions in 1998 stemming from nearly every cause. In 2000, capital and O&M work was performed based on inspections at a cost of $3,820 in *constant 1998 dollars*. Eighty-nine CSP transformers were converted to traditional transformers at a cost of $210,759 in *constant 1998 dollars*.

Mt. Vernon 131 – WPC 1998

This circuit was trimmed in 2000 and will be patrolled in 2002. Animal guards and lightning protection will be installed on all new transformers to reduce future outages. A problem three-phase regulator outside of the substation was replaced with 3 single-phase regulators to correct a voltage problem. Reclosers will be replaced and upgraded at a cost of $23,223 in *constant 1998 dollars*.

1999 Worst Performing Circuit Remediation

Table 29 shows the 1999 WPCs and their performance in 1998, 1999, and 2000. Maryville 368 was a worst performing circuit in 1998 and is again in 2000. The following paragraphs will outline the projects preformed since 1998 on each circuit.

• Table 29. 1999 Worst Performing Circuit with Previous and Subsequent Performance

1999 Worst Performing Circuits			1999 Performance			2000 Performance			1998 Performance		
Area Name	Area	Circuit	SAIFI	CAIDI	CAIFI	SAIFI	CAIDI	CAIFI	SAIFI	CAIDI	CAIFI
Belleville	51	222	**4.18**	144	**4.18**	1.53	202	1.99	N/A	N/A	N/A
Bloomington	31	202	**4.11**	219	**4.11**	1.67	410	1.83	3.91	310	3.79
Champaign	32	116	0.98	62	**12.56**	1.76	136	2.13	0.22	189	1.14
Champaign	32	541	0.35	**753**	1.09	0.07	56	1.00	1.33	144	1.31
Decatur	35	128	**5.49**	96	**5.49**	1.72	109	1.86	5.56	78	5.33
Decatur	35	161	**3.92**	133	**4.49**	0.82	81	1.09	1.49	143	1.40
Decatur	35	215	0.09	**673**	1.39	0.00	0	0.00	0.01	23	1.00
Granite City	64	296	**4.15**	84	**4.15**	2.05	108	2.11	0.25	132	1.25
Hillsboro	66	812	**4.36**	144	**5.08**	2.74	116	2.89	0.91	147	1.50
Jacksonville	36	110	0.06	**787**	1.52	0.05	393	1.00	1.10	71	1.04
Jacksonville	36	331	**4.09**	500	4.09	0.75	101	2.15	1.82	102	1.70
Maryville	51	293	0.47	**658**	1.00	0.75	284	1.48	1.96	133	1.91
Mt. Vernon	72	104	0.14	**1163**	1.00	1.06	135	1.10	2.41	153	2.27
Mt. Vernon	72	112	0.10	**716**	1.00	0.92	76	1.14	1.46	65	1.35
Mt. Vernon	72	156	0.13	**817**	1.00	0.26	180	1.00	0.32	119	1.06
Sparta	73	904	0.04	**1072**	1.11	0.03	294	1.00	0.36	582	1.01
Sparta	73	915	**4.64**	215	**4.64**	1.52	115	1.57	1.26	39	1.22
Sparta	73	916	**7.85**	188	**7.85**	1.79	147	1.96	5.46	167	5.28
Sparta	73	928	1.05	**1292**	1.07	0.12	97	1.11	0.66	113	1.84
Sparta	73	934	**4.36**	214	**4.36**	0.57	128	1.62	2.32	112	2.53
Sparta	73	935	1.23	**672**	1.26	0.03	192	1.27	7.82	117	7.52

Belleville 222 – WPC 1999

The largest event recorded on this circuit was due to wind and it occurred on June 11, 1999: one of the abnormal days. In 1999, an animal guarding project was performed at a cost of $948 in *constant 1998 dollars*.

In 2000, the following projects were performed:

- A fuse coordination study with recommendations being implemented,
- Forty poles were replaced, and
- CSP transformers were converted to conventional tanks.

These projects were performed at a cost of $88,059 in *constant 1998 dollars*.
Maintenance work identified from patrols was conducted at a cost of $10,323 in *constant 1998 dollars*.

Bloomington 202 – WPC 1999

Wind and vehicles caused the majority of customers interrupted and customer minutes interrupted during 1999. There were a number of smaller events caused by equipment failure. The Area has done a significant number of projects on this circuit in 2000:

- Replaced poles,
- Rebuilt Line Sections,
- Converted some line sections from 6 cu to 477, and
- Upgraded reclosers and fuses.

This work was performed at a cost of $261,302 in *constant 1998 dollars*.

Champaign 116 – WPC 1999

There were two large events on this circuit in 1999: (1) an animal cause event and (2) defective pin. The local Area performed the following projects in 2000:

- Rebuilt a portion of the main line,
- Re-conductored a portion of the main line,
- Added animal guards, and
- Performed spacer repairs.

These projects were performed at a cost of $55,333 in *constant 1998 dollars*.

Champaign 541 – WPC 1999

A fire at the lumberyard caused the largest event on this circuit. If the fire had not occurred, this circuit would not have been one of the worst performers. The local Area rebuilt the portion of the line that was damaged by the fire at a cost of $14,218 in *constant 1998 dollars*.

Decatur 128 – WPC 1999

This circuit was a worst performer and had numerous events from underground cable failures and animal intrusions. There were also some interruptions due to wind and lightning. In 1999, the local Area replaced some sections of underground cable at a cost of $5,213 in *constant 1998 dollars*. In 1999, the Area also protected the substation against animal intrusions at a cost of $3,792 in *constant 1998 dollars*. Also, $12,038 (in *constant 1998 dollars)* was spent on planning projects to enhance coordination on the circuit and will be completed in 2001.

Decatur 161– WPC 1999

This circuit was a worst performing circuit because of lightning, overhead equipment problems, and a failed recloser. During 1999, the local Area replaced underground sections on this feeder at a cost of $1,896 in *constant 1998 dollars*.

Decatur 215 – WPC 1999

This circuit made the worst performing circuit list due to one large wind event. Historically, it has experienced good reliability performance in 2000. No additional work was required or performed on this circuit.

Granite City 296– WPC 1999

This circuit made the worst performing circuit list due to numerous lightning events in 1999. As described in the section on Lightning Analysis on page 23, IP is currently investigating lightning protection options. IP will also employ their new reliability methodology to identify areas that require reliability mitigation and to determine the specific programs required.

Hillsboro 812– WPC 1999

This circuit truly was a worst performing circuit and experienced numerous interruptions in 1999. The predominant causes were lightning, wind, trees, and scheduled. The local Area drafted a mitigation plan. In 1999, the local Area rebuilt a portion of the circuit and replaced poles at a cost of $12,315 in *constant 1998 dollars*. In 2000, the local Area:

- installed more than 185 lightning arresters,
- replaced bad poles,
- replaced a CSP transformer, and
- upgraded a station

at a cost of $40,901 in *constant 1998 dollars*. In 2001, the local Area upgraded fusing in several locations and rebuilt several overhead line sections at a cost of $65,799 in *constant 1998 dollars*. More work is planned during 2001.

Jacksonville 110– WPC 1999

This circuit made the worst performing circuit list due to a substation event and three smaller wind events. The local Area performed hot spot trimming in 1999 at a cost of $948 in *constant 1998 dollars*. Regular cycle trimming will be complete in May 2001. The local Area also animal proofed the whole feeder during 2000 at a cost of $15,247 in *constant 1998 dollars*.

Jacksonville 331– WPC 1999

This circuit made the worst performing circuit list due to three event types: (1) a large wind event, (2) an animal event, and (3) some lightning events. This circuit was last trimmed in 1998. In 2000, the local Area replaced:

- Replaced eight poles,
- Replaced eight cross arms,
- Replaced two insulators,
- Replaced three lightning arresters,
- Completed Animal Protection on the entire circuit,

at a cost of $17,664 in *constant 1998 dollars*.

Maryville 293– WPC 1999

This circuit made the worst performing circuit list due to one wind event on an abnormal day. The reliability performance during 2000 was good. The local Area performed some work on this circuit in 2000 to upgrade reclosers and make repairs at a cost of $2,844 in *constant 1998 dollars*.

Mt. Vernon 104– WPC 1999

This circuit made the worst performing circuit list due to one event during a major ice storm that was classified as an abnormal day. This circuit was last trimmed in 1998. In 1999, blown lightning arresters were replaced at cost of $1,896 in *constant 1998 dollars*. During 2000, spacer cable was replaced and a bad pole in the substation was replaced at a cost of $9,005 in *constant 1998 dollars*. This circuit had good performance in 2000.

Mt. Vernon 112– WPC 1999

This circuit made the worst performing circuit list due to one event during a major ice storm that was classified as an abnormal day. This circuit was last trimmed in 1999. The local Area replaced a non-standard transformer, a bad substation pole, repaired spacer cable, and performed miscellaneous repair items discovered on the maintenance patrol at a cost of $22,749 in *constant 1998 dollars*. This circuit had good performance in 2000.

Mt. Vernon 156– WPC 1999

This circuit made the worst performing circuit list due to one event during a major ice storm that was classified as an abnormal day and one underground cable failure. This circuit was last trimmed in 1999. The local Area installed substation circuit tie switches in 1999 at a cost of $7,962 in *constant 1998 dollars*. The local Area changed out a recloser during 2000 at a cost of $1,422 in *constant 1998 dollars*. This circuit had good performance in 2000.

Sparta 904– WPC 1999

This circuit made the worst performing circuit list due to one wind, one tree and one ice event during a major ice storm that was classified as an abnormal day This circuit was last trimmed in 1999. During 2000, the local Area replaced a cross arm and lightning arresters at a cost of $1,042 in *constant 1998 dollars*. This circuit had good performance in 2000.

Sparta 915– WPC 1999

This circuit made the worst performing circuit list due to one event during the ice storm, two lightning events, one wind event, and multiple underground cable failures. In 1999, the local Area replaced 3 sections of underground cable at a cost of $8,910 in *constant 1998 dollars*. In 2000, the local Area replaced two bad poles and performed maintenance on the circuit at a cost of $7,763 in *constant 1998 dollars*.

Sparta 916– WPC 1999

This circuit made the worst performing circuit list because of the ice storm and weather/lightning events during the summer. In 1999, the local Area replaced some underground cable at a cost of $2,465 in *constant 1998 dollars*. In 2000, the local Area replaced:

- Seventy CSP transformers with traditional transformers,
- Replaced seven bad poles, and
- Performed maintenance work identified by the line patrol

at a cost of $27,688 in *constant 1998 dollars*.

Sparta 928– WPC 1999

This circuit only made the worst performing circuit list due to the ice storm, which was an abnormal event. In 2000, the local Area replaced one bad pole and performed maintenance work identified by the line patrol at a cost of $3,379 in *constant 1998 dollars*.

Sparta 934– WPC 1999

This circuit was heavily impacted during the ice storm, which was designated as an abnormal day. Animals, overhead equipment failures, and wind also affected this circuit. In 1999, the Area replaced four spans of overhead conductor and two poles at a cost of $2,803 in *constant 1998 dollars*. In 2000, the Area replaced forty-four bad poles and performed maintenance work identified by the line patrols at a cost of $51,964 in *constant 1998 dollars*. Also installed 246 lightning arresters at a cost of 47,395 in *constant 1998 dollars*.

Sparta 935– WPC 1999

This circuit made the worst performing circuit list due to the ice storm that occurred on an abnormal day. It was last trimmed in 1995, but had no appreciable wind or tree interruptions in 1999 with the exception of the ice storm and will be trimmed in 2001. In 2000, the local Area replaced eighty-nine CSP transformers with conventional tanks and performed both capital and maintenance work identified by the line patrol at a cost of $24,579 in *constant 1998 dollars*.

K) *Commencing June 10, 2001, tables or graphical representations, covering for the last three years all of the jurisdictional entity's customers and showing, in ascending order, the total number of customers that experienced a set number of interruptions during the year (i.e., the number of customers who experienced zero interruptions, the number of customers who experienced one interruption, etc.).*

This section is not required until June 1, 2002.

L) *Commencing June 10, 2001, for those customers who experienced interruptions in excess of the service reliability targets, a list of every customer, identified by a unique number assigned by the jurisdictional entity and not the customer's name or account number, the number of interruptions and interruption duration experienced in each of the three preceding years, and the number of consecutive years in which the customer has experienced interruptions in excess of the service reliability targets.*

This section is not required until June 1, 2002.

M) *The name, address and telephone number of a jurisdictional entity representative who can be contacted for additional information regarding the annual report.*

John Barud
Senior Director - Electric Delivery
Illinois Power Company
500 South 27th Street
Decatur, IL 62525

Telephone (217) 475-8433
Fax (217) 475-8449

c) *Customer report. A jurisdictional entity shall, upon request made by a customer or the Consumer Services Division of the Commission, provide to the customer and/or the Consumer Services Division, within thirty days after the request, a report on all interruptions that the customer making the request, or subject to the Consumer Service Division's request, has experienced at the customer's current service location during the most recent five calendar years. The report shall identify for each interruption the information specified in Section 411.110(a)(1)(A)-(D). Notwithstanding the provisions of this subsection, a jurisdictional entity is not required to report data pursuant to this Section that Section 411.110(b) does not require a jurisdictional entity to maintain, or which the jurisdictional entity was not required to retain at the time of the interruption. This subsection does not alter the provisions of 83 Ill. Adm. Code 200 and 280 that relate to informal and formal complaint procedures.*

Section 411.130 Interruption Cause Categories

In adhering to the interruption record-keeping and reporting requirements set forth in this Part, each jurisdictional entity shall classify and report on the cause of each interruption using the cause categories and interruption code descriptions given in Table A of this Part.

Table 30 shown below details information based on all sustained interruptions with no exclusions.

• Table 30. Exhibit 411.130 - Summary of Interruptions by Cause Category

Cause Category	Customer Minutes Interrupted	Customers Interrupted	Events
ARES OR OTHER TOTAL UTILITY	3,963,495	22,296	42
CUSTOMER	299,206	6,788	138
FORESTRY	8,073,572	50,180	1,564
INTENTIONAL	7,709,267	99,168	3,585
JURSIDCTIONAL ENTITY/CONTRACTOR PERSONNEL ERRORS	583,350	14,675	147
OH EQUIPMENT RELATED	14,760,475	122,312	4,107
OTHER	223,522	2,837	119
PUBLIC	7,833,878	52,683	1,245
TRANSMISSION & SUBSTATION EQUIPMENT RELATED	7,648,618	138,708	250
UG EQUIPMENT RELATED	4,664,460	25,910	1,251
UNKNOWN	604,460	9,615	211
WEATHER	107,113,026	408,704	6,675
WILDLIFE	11,592,509	142,581	3,693

Section 411.140 Reliability Review

a) *Beginning in the year 1999 and at least every three years thereafter, the Commission shall assess the annual report of each jurisdictional entity and evaluate its reliability performance. Within thirty days after receiving the Commission's final report on such assessment, the jurisdictional entity may prepare a response to such report. Both the Commission's final report and the jurisdictional entity's response shall be filed with the Chief Clerk of the Commission.*

1) *The Commission recognizes that circumstances and events beyond a jurisdictional entity's control can affect reliability statistics and the interruptions experienced by customers. The Commission shall consider such circumstances and events when evaluating a jurisdictional entity's reliability performance.*

2) *The Commission evaluation shall:*

A) *Assess the jurisdictional entity's historical performance relative to established reliability targets.*
B) *Identify trends in the jurisdictional entity's reliability performance.*
C) *Evaluate the jurisdictional entity's plan to maintain or improve reliability.*
D) *Include specific identification, assessment, and recommendations pertaining to any potential reliability problems and risks that the Commission has identified as a result of its evaluation.*
E) *Include a review of the jurisdictional entity's implementation of its plan for the previous reporting period.*

b) *Annual report assessment and reliability performance evaluation criteria.*

1) *When assessing a jurisdictional entity's annual report, the Commission shall consider the information listed below.*

A) *Information that this Part requires a jurisdictional entity to include in annual reports.*
B) *The relevant characteristics of the area served, including but not limited to system configuration, population density, and geographical constraints.*
C) *The age and condition of the system's equipment and facilities.*
D) *Generally accepted engineering practices.*
E) *The costs of potential actions.*
F) *The benefits of avoiding the risks of service disruptions.*
G) *The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.*

2) *Criteria for Commission assessment of a jurisdictional entity's annual report.*

A) *The report must comply with the requirements of this Part.*
B) *The report must contain a plan, as required by Section 411.120(b)(3)(A).*

3) *When assessing a jurisdictional entity's reliability performance, the Commission shall consider the information listed below.*

A) *Controllable interruptions.*
B) *Statistical measures of interruptions.*
C) *The number of interruptions experienced by individual customers.*
D) *The cumulative hours of interruption experienced by individual customers.*
E) *The jurisdictional entity's actions to prevent interruptions.*
F) *The jurisdictional entity's responses to interruptions and to the customers affected by interruptions.*
G) *The extent to which the jurisdictional entity has restored interruptions of service to customers on a non-discriminatory basis without regard to whether a customer has chosen the jurisdictional entity or another provider of electric power and energy.*
H) *The number and substance of informal inquiries, requests for assistance, and complaints directed by customers to the jurisdictional entity and to the Commission.*
I) *The results of customer satisfaction surveys that include customer perceptions of service reliability.*
J) *Generally accepted engineering practices.*
K) *The costs of potential actions.*

L) *The benefits of avoiding the risks of service disruptions.*
M) *The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.*
N) *Previous Commission reports and the jurisdictional entity's responses to those reports.*
O) *Information that this Part requires a jurisdictional entity to include in annual reports.*
P) *The relevant characteristics of the area served, including but not limited to system configuration, population density, and geographical constraints.*
Q) *The age and condition of the system's equipment and facilities.*

4) *The jurisdictional entity shall strive to provide electric service to its customers that comply with the targets listed below.*

A) *Customers whose immediate primary source of service operates at 69,000 volts or above should not have experienced:*

i) *More than three controllable interruptions in each of the last three consecutive years.*
ii) *More than nine hours of total interruption duration due to controllable interruptions in each of the last three consecutive years.*

Not required to report until the 2001 Annual Report.

B) *Customers whose immediate primary source of service operates at more than 15,000 volts, but less than 69,000 volts, should not have experienced:*

i) *More than four controllable interruptions in each of the last three consecutive years.*
ii) *More than twelve hours of total interruption duration due to controllable interruptions in each of the last three consecutive years.*

Not required to report until the 2001 Annual Report.

C) *Customers whose immediate primary source of service operates at 15,000 volts or below should not have experienced:*

i) *More than six controllable interruptions in each of the last three consecutive years.*
ii) *More than eighteen hours of total interruption duration due to controllable interruptions in each of the last three consecutive years.*

Not required to report until the 2001 Annual Report.

D) *Exceeding the service reliability targets is not, in and of itself, an indication of unreliable service, nor does it constitute a violation of the Act or any Commission order, rule, direction, or requirement. The Commission's assessment shall determine if the jurisdictional entity has a process in place to identify, analyze, and correct service reliability for customers who experience a number or duration of interruptions that exceeds the targets.*

Section 411.150 Modification or Exemption

a) *Any jurisdictional entity may file an application requesting modification of or exemption from any Section of this Part as such Section applies to the jurisdictional entity filing the application. For good cause shown and upon a showing that such a waiver will not compromise the reliability obligations of the jurisdictional entity, the Commission may grant such a request for modification or exemption, except that the Commission may not grant any modification or exemption of specific requirements stated in Section 16-125 of the Act [220 ILCS 5/16-125]. A petition for exemption or modification shall be filed pursuant to 83 Ill. Adm. Code 200 and shall set forth specific reasons and facts in support of the requested exemption or modification.*

b) *In determining whether good cause has been shown, the Commission shall consider, among other things, the information listed below.*

   1) *The extent to which circumstances beyond the control of the jurisdictional entity have made compliance with the applicable Section extremely difficult.*
   2) *Whether the jurisdictional entity has made a good faith effort to comply with the applicable Section in a timely fashion.*
   3) *Whether other information, which the jurisdictional entity would provide if the waiver is granted, permits the Commission Staff to review the subject filing in a complete, timely and meaningful manner.*

Illinois Power did not request any exemption or modification for 2000.

Section 411.160 Format and Disclosure of Reports

The reports required to be filed by this Part shall be submitted to the Commission and available to the public in both printed and electronic form. The printed version shall be the official version filed with the Commission's Chief Clerk. Computerized data and information filed as part of a report that is stored by a jurisdictional entity on a personal computer shall be provided in Microsoft Office or Corel Office, IBM personal computer compatible file formats and delivered to the Commission's offices via Internet electronic mail or on floppy disks or other portable storage media as agreed to by the Commission Staff. Underlying data provided to the Commission shall be available to the public to the extent that it is not proprietary information. A jurisdictional entity shall report the required information on both a system-wide and operating areas basis. A jurisdictional entity shall submit the required information in a consistent format each year that facilitates comparisons across time periods and that uses non-technical language. A jurisdictional entity's reports shall be available to the public from the jurisdictional entity and from the Commission. A jurisdictional entity shall keep copies of its reports at its public offices.

No Response Required by the Company.

Section 411.170 Exclusions

The service reliability targets in this Part shall not apply to customers served under a Commission approved tariff or contract, or contract for competitive services as defined in Section 16-102 of the Act [220 ILCS 5/16-102], that specifies levels of service reliability different from the service reliability targets in this Part.

No Response Required by the Company.

Section 411.180 System Protection

a) *In the event that the equipment or facilities of a customer or other entity are being operated in a manner that is inconsistent with the jurisdictional entity's tariffs, terms and conditions of service, or any contract between the jurisdictional entity and the customer or other entity, and such operation poses, in the reasonable judgment of the jurisdictional entity, an imminent threat to the reliability of service to customers or to person or property, the jurisdictional entity shall have the right, but not the obligation, to immediately discontinue service to those points of service that supply power or energy to such equipment or facilities until such time as the threat can be eliminated and service restored. The jurisdictional entity shall give as much notice of such discontinuance of service as is reasonably possible to the affected customer. Temporary discontinuance of service pursuant to this Section shall be deemed to be in compliance with 83 Ill. Adm. Code 280.130(k).*

b) *Notwithstanding anything in the rules of the Commission to the contrary, a jurisdictional entity may lawfully take such actions as are required by federal law or standards adopted under federal law, or by an organization authorized by federal authority, to protect the security of the bulk power system and/or to provide for the continuous supply of power to facilities regulated under federal law.*

Section 411.190 Approval of Vegetation Management Programs

A jurisdictional entity may file with the Commission tariffs describing programs and practices for the control of vegetation designed to maintain or enhance service reliability. Such tariffs, if passed to file or accepted after hearing, shall be deemed standards of the Commission with respect to vegetation management by such jurisdictional entity and shall pre-empt contrary ordinances, rules, and actions of units of local government. A jurisdictional entity will provide notice to municipalities and counties directly affected thereby of the filing, under this Section, of a proposed tariff or supporting materials relating to the need for such a tariff.

On December 6th, 2000 Illinois Power filed a proposed Vegetation Management Tariff with the Illinois Commerce Commission. The purpose of the tariff was to provide the basic standards and guidelines desired for appropriate vegetation management. This would result in enhancing Illinois Power's ability to provide the maximum practical level of electric service, reliability and safety at the least cost to customers.

In response to the proposed tariff, several communities expressed concern with respect to portions of the standards and guidelines. Based on their concerns and the need to establish a tariff that has the support of the communities that Illinois Power serves, the Company withdrew the proposed tariff with its request to the ICC on March 21, 2001. The parties are currently working together to formulate a mutually agreed upon plan. Discussions began in February 2001 with the joint goal being the development of a plan to achieve a balance between each community's concern for maintaining healthy and aesthetic vegetation and the utility's need to provide safe and reliable electric service through proven and effective vegetation management practices.