Iowa Electric Reliability Rules, 199 IAC 20.18

Margaret Munson and Don Stursma, IUB

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http://www.legis.state.ia.us/aspx/ACODocs/DOCS/9-7-2011.199.20.pdf

Service reliability requirements for electric utilities apply to:

- Investor-owned electric utilities and electric cooperative corporations and associations operating within the state of Iowa subject to Iowa Code chapter 476.
- The construction, operation, and maintenance of electric transmission lines by electric utilities.

Utilities shall:

1. Make reasonable efforts to avoid and prevent interruptions of service.
2. Reestablish service within the shortest time practicable, consistent with safety.
3. Design, construct, maintain, and electrically reinforce and supplement facilities to reliably perform in the storm and traffic hazard environment in which they are located.
4. Carry on an effective preventive maintenance program.
5. Be capable of emergency repair work on a scale which its storm and traffic damage record indicates as appropriate to its scope of operations and to the physical condition of its transmission and distribution facilities.
6. Keep records of interruptions of service on its primary distribution system.
7. Make an analysis of the records for the purpose of determining steps to be taken to prevent recurrence of such interruptions.
8. Make reasonable efforts to reduce the risk of future interruptions by:
    a. Taking into account the age, condition, design, and performance of transmission and distribution facilities; and
    b. Providing adequate investment in the maintenance, repair, replacement, and upgrade of facilities and equipment.

The Board will consider:

a. The condition of the physical property; and
b. The size, training, supervision, availability, equipment, and mobility of the maintenance forces.

Reliability and service quality record keeping for utilities with more than 50,000 Iowa retail customers. Each meter equals one customer.

Each electric utility shall maintain a geospatial information system (GIS) and an outage management system (OMS) sufficient to determine a history of sustained electric service interruptions experienced by each customer, in order to determine a history of electric service interruptions. Records shall be maintained for seven years. Data shall be sortable by each and any combination of the following factors:

1. State jurisdiction;

2. Operating area (if any);
3. Substation;
4. Circuit;
5. Number of interruptions in reporting period; and
6. Number of hours of interruptions in reporting period.

Records on interruptions shall be sufficient to determine the following:

1. Starting date and time the utility became aware of the interruption;
2. Duration of the interruption;
3. Date and time service was restored;
4. Number of customers affected;
5. Description of the cause of the interruption;
6. Operating areas affected;
7. Circuit number(s) of the distribution circuit(s) affected;
8. Service account number or other unique identifier of each customer affected;
9. Address of each affected customer location;
10. Weather conditions at time of interruption;
11. System component(s) involved (e.g., transmission line, substation, overhead primary main, underground primary main, transformer); and
12. Whether the interruption was planned or unplanned.

Each electric utility shall maintain as much information as feasible on momentary interruptions.

Each electric utility shall keep information on cause codes, weather codes, isolating device codes, and equipment failed codes.

1. Cause code: animals, lightning, major event, scheduled, trees, overload, error, supply, equipment, other, unknown, and earthquake.
2. Weather code: wind, lightning, heat, ice/snow, rain, clear day, and tornado/hurricane.
3. Isolating device: breaker, recloser, fuse, sectionalizer, switch, and elbow.
4. Equipment failed: cable, transformer, conductor, splice, lightning arrester, switches, cross arm, pole, insulator, connector, other, and unknown.
5. Utilities may augment the code sets listed above to enhance tracking.

Each electric utility shall record the date of installation of major facilities (poles, conductors, cable, and transformers) installed on or after April 1, 2003, and integrate that data into its GIS database.

Annual reliability and service quality report for utilities with more than 50,000 Iowa retail customers. Each meter equals one customer. (See page 5 for definitions.)

a. *Description of service area.*

b. *System reliability performance.*

   1. An overall assessment of the reliability performance, including the urban and rural SAIFI, SAIDI, and CAIDI reliability indices for the previous calendar year for the Iowa service territory and each defined Iowa operating area, if applicable. These indices shall be calculated twice, once with the data associated with major events and once without.
   2. The urban and rural SAIFI, SAIDI, and CAIDI reliability average indices for the previous five calendar years for the Iowa service territory and each defined Iowa operating area, if applicable. These indices shall be calculated twice, once with the data associated with major events and once without.
   3. The MAIFI reliability indices for the previous five calendar years for the Iowa service territory and each defined Iowa operating area for which momentary interruptions are tracked.

c. *Reporting on customer outages.*

   1. The total number of customers that experienced set numbers of sustained interruptions during the year, shown for:
      a. All Iowa customers, excluding major events; and
      b. All Iowa customers, including major events.
   2. The total number of customers that experienced a set range of total annual sustained interruption duration during the year, shown for:
      a. All Iowa customers, excluding major events; and
      b. All Iowa customers, including major events.

d. *Major event summary*

   1. A description of the area(s) impacted by each major event;
   2. The total number of customers interrupted by each major event;
   3. The total number of customer-minutes interrupted by each major event; and
   4. Updated damage cost estimates to the electric utility's facilities.

e. *Information on transmission and distribution facilities.*

   1. Total circuit miles of electric distribution line in service at year's end, segregated by voltage level.
   2. Total circuit miles of electric transmission line in service at year's end, segregated by voltage level.

f. *Plans and status report.*

   1. A plan for service quality improvements, including costs, for the electric utility's transmission and distribution facilities that will ensure quality, safe, and reliable delivery of energy to customers.
      a. Include data for the three years following the year in which the annual report was filed. Copies of capital budgeting documents shall be maintained for five years.
      b. Identify reliability challenges and may describe specific projects and projected costs. The filing of the plan shall not be considered as evidence of the prudence of the utility's reliability expenditures.

   c. The plan shall provide an estimate of the timing for achievement of the plan's goals.
2. A progress report on plan implementation. The report shall include identification of significant changes to the prior plan and the reasons for the changes.

g. *Capital expenditure information.*
1. Each electric utility shall report on an annual basis the total of:
   a. Capital investment in the electric utility's Iowa-based transmission and distribution infrastructure approved by its board of directors or other appropriate authority.
   b. Capital investment expenditures in the electric utility's Iowa-based transmission and distribution infrastructure
2. Each electric utility shall report the same capital expenditure data from the past five years.

h. *Maintenance.*
1. Total maintenance budgets and expenditures for distribution, and for transmission, for each operating area, if applicable, and for the electric utility's entire Iowa system for the past five years.
2. Tree trimming.
   a. The total annual tree trimming budget expenditures shall be identifiable for each operating area and for the electric utility's entire Iowa system for the past five years.
   b. Total annual projected and actual miles of transmission line and of distribution line for which trees were trimmed.
   c. In the event the utility's actual tree trimming performance lags behind its planned trimming schedule by more than six months, the utility shall be required to file for the Board's approval additional tree trimming status reports on a quarterly basis.

i. *Poles.* The annual reliability report shall include the number of poles inspected, the number rejected, and the number replaced.

Definitions

CAIDI: *Customer average interruption duration index.* The average interruption duration for those customers who experience interruptions during the year, calculated by dividing the annual sum of all customer interruption durations by the total number of customer interruptions.

MAIFI: *Momentary average interruption frequency index.* The average number of momentary electric service interruptions for each customer during the year, calculated by dividing the total number of customer momentary interruptions by the total number of customers served.

SAIDI: *System average interruption duration index.* The average interruption duration per customer served during the year, calculated by dividing the sum of the customer interruption durations by the total number of customers served during the year.

SAIFI: *System average interruption frequency index. T*he average number of interruptions per customer during the year, calculated by dividing the total annual number of customer interruptions by the total number of customers served during the year.

Interruption duration: A period of time measured in one-minute increments that starts when an electric utility is notified or becomes aware of an interruption and ends when an electric utility restores electric service.

Major event: Declared whenever extensive physical damage to transmission and distribution facilities has occurred within an electric utility's operating area due to unusually severe and abnormal weather or event and:

1. Wind speed exceeds 90 mph for the affected area; or
2. One-half inch of ice is present and wind speed exceeds 40 mph for the affected area; or
3. Ten percent of the affected area total customer count is incurring a loss of service for a length of time to exceed five hours; or
4. 20,000 customers in a metropolitan area are incurring a loss of service for a length of time to exceed five hours.

Total number of customers served: The total number of customers served on the last day of the reporting period.

Notification of Outages, 199 IAC 20.19

On June 22, 2011, a rule making was commenced by the Board proposing to amend the requirements to change the length of the projected outage from two hours to six and to change the triggering activity to "when it is projected" that the outage will be longer than six hours.

The following is based on the rule in effect currently.

Purpose: The timely collection of electric outage information that may be useful to emergency management agencies. Each electric utility shall notify the Board when it becomes apparent that an outage may result in a loss of service for more than two hours and the outage meets one of the following criteria:

a. Loss of service for more than two hours to substantially all of a municipality, including the surrounding area served by the same utility. A utility may use loss of service to 75 percent or more of customers within a municipality, including the surrounding area served by the utility, to meet this criterion;

b. For utilities with 50,000 or more customers, loss of service for more than two hours to 20 percent of the customers in a utility's established zone or loss of service to more than 5,000 customers in a metropolitan area, whichever is less;

c. For utilities with more than 4,000 customers and fewer than 50,000 customers, loss of service for more than two hours to 25 percent or more of the utility's customers;

d. A major event; or

e. Any other outage considered significant by the electric utility.

Information required: Notification shall be provided to the Board duty officer by e-mail at iubdutyofficer@iub.iowa.gov or by telephone at (515)745-2332. Notification shall be made at the earliest possible time after it is determined the event may be reportable and should include the following information, as available:

a. The general nature or cause of the outage;

b. The area affected;

c. The approximate number of customers affected;

d. The time when service is estimated to be restored; and

e. The name of the utility, the name and telephone number of the person making the report, and the name and telephone number of a contact person knowledgeable about the outage.

The notice should be supplemented as more complete or accurate information is available.

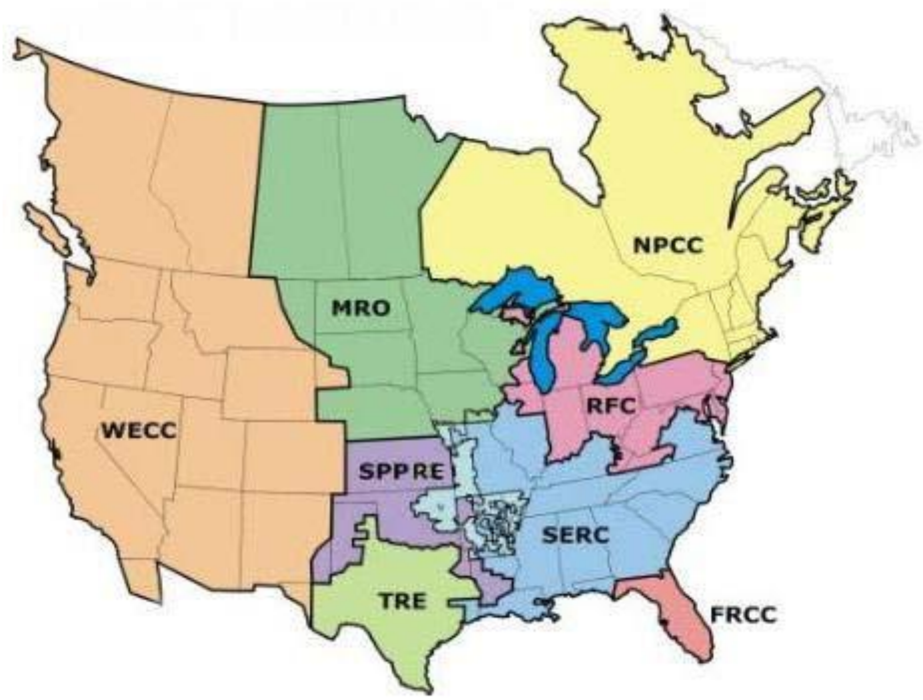
The utility shall provide to the Board updates of the estimated time when service will be restored to all customers able to receive service or of significant changed circumstances, unless service is restored within one hour of the time initially estimated.

North American Electric Reliability Corporation

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses reliability annually via a 10-year assessment and winter and summer preseasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas as shown on the map below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.

From the *NERC 2010 Long Term Reliability Report*, October 2010



FRCC
Florida Reliability Coordinating Council
SERC
SERC Reliability Corporation
MRO
Midwest Reliability Organization
SPP RE
Southwest Power Pool Regional Entity

NPCC
Northeast Power Coordinating Council
TRE
Texas Reliability Entity
RFC
Reliability*First* Corporation
WECC
Western Electricity Coordinating Council