Multi-State Electric Service Rules Comparison

September 11, 2019

Electric Operations Section
Energy Operations Division
Michigan Public Service Commission

Executive Summary

The Electric Operations Section researched what other states are doing in regards to service quality and reliability metrics in response to Governor Whitmer's February 2019 request for a statewide energy assessment.

The data that was gathered shows that there is no universal reliability number that is used to indicate acceptable or unacceptable performance across the nation. Many states require annual reliability reporting with some requiring extensive information. The majority of these states require reliability metrics such as SAIFI, SAIDI and CAIDI. We did not find a lot out about service credits and are still looking into that. Our current recommendations are to strengthen our Service and Reliability existing rules by:

- Expanding the annual reliability report to include all utilities, not just Consumers Energy and DTE Electric (Currently, Docket Nos. U-16065 and U-16066, respectively)
- Reduce the length of time for acceptable customer call answer time from 90 seconds to 45 or 30 seconds.
- Require annual reporting of reliability metrics SAIFI, SAIDI, CAIDI and CEMI for all utilities.
- Reduce annual same circuit Repetitive interruption factor from 5 outages to 4 outages and require utilities to pay the service credit if a customer experiences more than 5 outages instead of 7 outages.
- Require customers to receive automatic service credits if they qualify and eliminating the requirement for customers to apply for the credit.
- Increase service credits to $50.00 from $25.00.
- Consider mandating that fines go directly to customers instead of to the State.
- Consider mandating that utilities submit Annual Safety reports of OSHA incidents, and injuries requiring medical attention or property damage.
- Consider requiring the utilities to file their Emergency response plan every 5 years.
- Consider requiring an annual report from each utility after each major service interruption.

The following pages encompass the summation of our research.

New Service Connections[1]

- **California**
    - Customer contact within five business days.
    - Installation of service within three to five business days.
- **Illinois**
    - Two day application approval process. Four day installation timeframe for electric.
- **Indiana**
    - No specific timespan listed. For line extensions, Company won't start work until a deposit and/or payment is secured, but no timeline is listed. (170 IAC 4-1-27)
- **Massachusetts**
    - Percent of service appointments met as scheduled. Benchmark is average of most recent 10 years.
- **Minnesota**
    - None listed.
- **New Jersey**
    - New customer installations within 3-10 business days.
- **New York**
    - Home Energy Fair Practices Act (HEFPA) – Amendments of Chapter 686, the Laws of 2002 provides that utility must respond to new service requests within 5 business days and inform consumer is additional information is needed
- **Ohio**[2]
    - Electric – Companies must install service within **three days, or 10 days** if construction is needed for installation, of the date you specify. If the electric company is unable to meet these deadlines, they must notify you about the delay.

- **Washington State**
    - The Company will switch on power within one business day of the Customer or Applicants request for service. Exceptions: when construction is required before the service can be energized, when the customer does not provide evidence that all inspections are complete, when payments to the company have not been received, and when service has been disconnected for nonpayment or theft.
- **Wisconsin**
    - None listed.

[1]https://www.michigan.gov/documents/mpsc/Brattle_Report_to_DTE_on_Performance_Based_Regulation_120617_613150_7.pdf

[2] https://www.puco.ohio.gov/be-informed/consumer-topics/guide-to-establishing-utility-services/

MI – R 460.722 Unacceptable levels of performance during service interruptions.

California[3] – After major storms utilities must restore service in less than 12 hours on average. General Order 166, Standard 12: Commission will perform a review of utility performance following every Major Outage and sets a benchmark for the Commission to use in reviewing utility restoration performance only during Measured Events. Standard 12's benchmark states that a utility's restoration performance during a measured Event shall be presumed reasonable if the CAIDI is 570 or below and presumed unreasonable if the CAIDI is above 570.

Indiana Restoration times (normal and catastrophic)

170 C 4-1-23 Interruptions of service; timing; records

a. In general, ASAP, but no penalties for extended outages. Commission reviews after the storm is over and makes recommendations.

Illinois The jurisdictional entity shall strive to provide electric service to its customers that complies 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.

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.

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.

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[3] Source: http://www.cpuc.ca.gov/General.aspx?id=4965
http://www.cpuc.ca.gov/General.aspx?id=4968
During Emergencies and Disasters: http://docs.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/159184.htm

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

Massachusetts- Restoration of Service. Each Company shall restore service to its customers in a safe and reasonably prompt manner during all Service Interruptions and outages. During an Emergency Event, this shall include at a minimum, but not be limited to, implementing all applicable components of the Company's Emergency Response Plan related to restoration of service.

Minnesota[4] – Rule 7826.0600 subpart 2: Annually set, utility specific, reliability standards. "The commission shall set reliability performance standards annually for each utility in the form of numerical values for the SAIDI, SAIFI, and CAIDI for each of its work centers. These standards remain in effect until the commission takes final action on a filing proposing new standards or changes them in another proceeding."

Ohio—not explicitly, but via reliability reporting standards.

- Rule 4901:1-10-10 (Rule 10) of the Ohio Administrative Code requires Ohio's investor-owned electric utilities to file an annual report of their distribution reliability performance. Specifically, Rule 10 requires the electric utilities to report their performance using the SAIFI and CAIDI reliability measures.

- Performance Standards and Rule Violations – Rule 10 requires each electric utility to file performance standards for approval by the Public Utilities Commission of Ohio. The approved standards are minimum performance levels, and missing a standard for two consecutive years constitutes a rule violation. Performance standards can be revised if the utility files an application that is approved by the Commission following a legal process that is open to interested persons. Performance standards can also be revised by Commission order.

Washington-- RCW 80.28.010 2) Every gas company, electrical company, wastewater company, and water company shall furnish and supply such service, instrumentalities and facilities as shall be safe, adequate and efficient, and in all respects just and reasonable.

Wisconsin[5] – Rule PSC 113.0606 Interruptions of service. Part (3). Each utility shall notify the commission of any event described below involving bulk power supply facilities (any generating unit or electric facilities operating at a nominal voltage of 69 kV or higher):

a. Any interruption or loss of service to customers for 15 minutes or more to aggregate firm loads in excess of 200,000 kW.

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[4] Source: https://www.revisor.mn.gov/rules/7826/

[5] Source: https://docs.legis.wisconsin.gov/code/admin_code/psc/113

b. Any interruption or loss of service to customers for 15 minutes or more to aggregate firm loads exceeding the lesser of 100,000 kW or half of the current annual system peak load and not required to be reported under part a.
c. Any decision to issue a public request for reduction in use of electricity.
d. Any action to reduce firm customer loads by reduction of voltage for reasons of maintaining adequacy of bulk electric power supply.
e. Any action to reduce firm customer loads by manual switching, operation of automatic load shedding devices, or any other means for reasons of maintaining adequacy of bulk electric power supply.

(4) Each utility shall notify the commission of service interruptions not involving bulk power supply facilities as follows:

a. Interruptions of 60 minutes or more to an entire distribution substation bus or entire feeder serving either 500 or more customers or entire cities or villages having 200 or more customers shall be reported within 2 weeks by a written report.

This differs from Michigan, as Michigan rule 460.722 focuses on restoration times (36 hours, 60 hours, etc.) and percent of customers restored (90%). However, Michigan utilities are required to notify the Commission and Commission Staff when outages reach a certain threshold.

MI – R 460.723 Wire down relief efforts.

California[6] – None found.

Indiana: No specific wire down standards

Illinois: No specific wire down standards

Massachusetts:
Priority One-Wires-Down Calls with the nearest trained resource,
Priority Two-Wires-Down Calls with the next available trained resource, and
Priority Three-Wires-Down Calls with capable resources
b. responding to customer-reported (i.e., non-priority) wires-down calls and ensuring that customer-reported wires-down calls do not pose a public safety threat; and
c. tracking and reporting, at a minimum, the following priority wiresdown data:
(1) date and time call received;
(2) priority level;
(3) date and time first Company resource arrived on the scene;
(4) time between call received and first Company resource arrived on the scene; and (5) date and time of repair.

Minnesota[7] – Rule 7826.0400 Annual Safety Report. On or before April 1 of each year, each utility shall file a report on its safety performance during the last calendar year. The report must include, among other things, a description of all incidents during the calendar year in which an injury requiring medical attention or property damage resulting in compensation occurred as a result of **downed wires** or other electrical system failures and all remedial action taken as a result of any injuries or property damage described.

Ohio: Company must have procedure in place to tend to wire downs, but PUCO does not have actual benchmarked standards. PUCO will approve the plan that the utility develops.

Washington: Average time from customer call to arrival of field technicians in response to electric system emergencies, per year = no more than 80 minutes (excludes MEDs).

Wisconsin[8] – PSC 113.0608 Emergency Response. Each utility with 25,000 customers or more shall establish procedures to record and monitor its response times for emergencies, such as… any calls or reports of wire contacts, dig-ins, wires down… In general, the records of these calls should include the date and time received; the identity (if known) of the caller; the identity of the person receiving the call;

[6] Source: http://www.cpuc.ca.gov/General.aspx?id=4965
[7] Source: https://www.revisor.mn.gov/rules/7826/

[8] Source: https://docs.legis.wisconsin.gov/code/admin_code/psc/113

the location and nature of the problem, incident, or accident; the time the utility responder arrived at the location; the total time to respond; and the final disposition or resolution of the problem.

Note: It is recognized that strict compliance with this rule may be difficult during major system-wide or large area emergencies, for example, major wind or ice storms where many outage reports may also involve reports of “wires down.” However, reasonable efforts should still be made to identify and give priority response to calls for assistance from police and fire officials who may be “first responders.” This will allow these locations to be secured so the police or fire units can be released to pursue other duties.

PSC 113.0512 Identification of potential power line natural hazards.

(3) Response to Identification of Potential Power Line Natural Hazards. Upon identifying a potential power line natural hazard, the utility shall take action to eliminate the hazard to the power line. The utility shall make a reasonable effort to notify the owner or other individual with authority, to trim or remove the tree of the potential danger and method by which the danger may be minimized or removed. Nothing in this section shall preclude the utility’s obligation to immediately remove the hazard, as required by ch. PSC 114.

Michigan rule 460.723 has specific metrics. The Wisconsin rule PSC 113.0608 only requires that procedures be established to record and monitor response times for emergencies.

MI – R 460.732 Annual report contents.

California[9]- Annual Reliability Reports of the major electric utilities include the following information:

- Duration and frequency of sustained and momentary outages using SAIDI, SAIFI, and MAIFI, with and without excludable major events for the past 10 years.
- The top ten power outage events based on customer-minutes, excluding events such as weather, declared emergencies, or disasters affecting over 10% of the utility's customers.
- Circuits in which customers have experienced greater than twelve sustained outages in a reporting year.

Similar to California, annual reports filed in Michigan focus on seeing if the utilities met certain performance metrics. However, the metrics are different.

Illinois Reporting Requirements: Section 411.120

- Must provide notice to Consumer Services Division of ICC for interruptions for 10,000 or more customers for three hours or more.
- After three hours of interruption, Company must inform CSD within one hour when the notice would be provided during normal business hours or within the first hour of the next business day.
- Must provide updates every two hours during normal business day until all service is restored to customers involved.
- Annual Report to be filed on or before June 1 of each year

- Reliability Review: Section 411.140
    - Commission to review Company's annual reports and evaluate its reliability performance based on several criteria.
- Vegetation Management Program: 411.190
    - Commission approves each utility VM program

Indiana: Each investor-owned electric utility (IOU) in Indiana is required to file a reliability report annually with the Indiana Utility Regulatory Commission (IURC) in compliance with 170 IAC 4-1-23(e).i

Each investor-owned utility shall file a reliability indices report with the commission's electricity division on or before March 1 of each year. The first report filed under this section shall include data from the previous three (3) calendar years. Subsequent reports filed under this section shall include data only from the previous calendar year. The report shall contain the following information:

(1) The reliability indices SAIDI, CAIDI, and SAIFI, with and without major events, for the utility's system and for each district or region into which its system may be divided. The utility shall report these data and analyses on a form prescribed by the commission.

(2) The definition of major event used by the utility for reporting purposes.

[9] Source: http://www.cpuc.ca.gov/General.aspx?id=4965

(3) For the reported indices, the number of customers used for the calculations and the utility's definition of customer. If a REMC maintains sufficient electronic records to comply with this subsection, the cooperative utility shall file a reliability indices report under this subsection.

(f) The commission may require that data be reported by the utilities in order to determine whether a utility is providing service consistent with this rule. The utility shall maintain historical CAIDI, SAIDI, SAIFI, and supporting data needed to calculate those indexes for a minimum of seven (7) years[10].

Illinois: Electric Reliability Pursuant to (220 ILCS 5/16-125) Sec. 16-125 of the Illinois 220 ILCS 05 - Public Utilities Act and the Commission's electric reliability rules in 83 Illinois Administrative Code, Part 411, all electric utilities are required to annually file an electric reliability report. The utilities file these reports with the Commission by the end of May for the previous calendar year. The annual utility reports are on the ICC web site under the headings "Self Assessments".

The ICC Staff is required to perform an assessment of each utility's reliability report, at least every three years per 83 Ill. Adm. Code 411.140. The assessments include a review of the annual reliability reports and evaluate the reliability performances. The Staff assessment reports are on the ICC web site under the heading "ICC Assessments".

Massachusetts

Reliability – SAIDI and SAIFI (statewide standards are not appropriate at this time due to inconsistencies in the way reliability is calculated amongst utilities).

Emergency response plans (ERP) are submitted to the Commission annually. G.L.c. 164 85(b)

Service quality Guidelines – complaints per 1,000 customers and service appointment commitments. DPU 12-120-D.

Minnesota[11]- Rule 7826.0500 Reliability Reporting Requirements.

Subpart 1. Annual reporting requirements. On or before April 1 of each year, each utility shall file a report on its reliability performance during the last calendar year. This report shall include information regarding the utility’s SAIDI, SAIFI, and CAIDI; explanation of how the utility normalizes its reliability data to account for major storms; circuit interruption data; and numerous other reporting requirements.

7826.1300 ANNUAL SERVICE QUALITY REPORT FILING.

On or before April 1 of each year, each utility shall file a report on its service quality performance during the last calendar year. These filings must be treated as "miscellaneous tariff filings" under the

[10] (Indiana Utility Regulatory Commission; No. 33629: Standards of Service For Electrical Utilities Rule 21; filed Mar 10, 1976, 9:10 a.m.: Rules and Regs. 1977, p. 355; readopted filed Jul 11, 2001, 4:30 p.m.: 24 IR 4233; filed Oct 18, 2004, 2:40 p.m.: 28 IR 789; readopted filed Apr 24, 2007, 8:21 a.m.: 20070509-IR-170070147RFA; readopted filed Aug 2, 2013, 2:16 p.m.: 20130828-IR-170130227RFA)

[11] Source: https://www.revisor.mn.gov/rules/7826/

commission's rules of practice and procedure, part 7829.0100, subpart 11. This report must include at least the information set forth in parts 7826.1400 to 7826.2000.

Ohio: Each utility must file annual report with Commission by March 31st detailing system condition, money spent for maintenance and reliability issues among other things.

> • The annual report must include the following information: – System-wide SAIFI and CAIDI performance for the year compared to wide SAIFI and CAIDI performance for the year compared to the utility's standards – Separate data for the utility's performance during major events and transmission outages –supporting the above performance – Outage-by-cause data, including outages, customers interrupted, and customer minutes interrupted • If the utility misses a standard, it must submit an action plan, which shall include: – The factors contributing to the miss –proposal for improving performance to meet the standard, including each action and its planned completion date
>
> An EDU is in violation if it misses the same performance standard two years in a row. standard two years in a row. (Rule: 4901:01 (Rule: 4901:01 -10 -30) • Sanctions for such a violation may include: –Corrective action to return to compliance – Restitution to customers – Fines up to $10,000 per day • Staff investigates each miss to determine what action to take • Actions could range from no action at all to recommending the maximum fine

New Jersey

Reliability – NJAC 14:5-7 measures reliability in terms of two indices CAIDI and SAIFI metrices are reported annually after a benchmark is set along with worse performing circuits.

14:5-8.2 Reliability Performance Levels

(a) Each EDC shall take reasonable measures to perform better (that is, to have lower numerical values) than the minimum reliability levels for CAIDI and SAIFI in N.J.A.C. 14:5-8.5.
(b) Performance that is worse (that is, that has higher numerical values) than the minimum reliability levels for CAIDI and SAIFI in this subchapter is a violation of this chapter and may be subject to penalty.

14:5-8.3 Service Reliability

(a) Each EDC shall have reasonable programs and procedures necessary to maintain the minimum reliability levels for its respective operating areas.
(b) The programs shall be designed to sustain reliability and, where appropriate, improve reliability. Each EDC shall utilize appropriate and qualified resources to maintain at a minimum, the minimum reliability levels for its respective operating areas.
(c) Interruptions shall not be reduced by characterizing a sustained interruption as a series of momentary event interruptions. Electric service interruptions shall be reported in accordance with N.J.A.C. 14:3-3.7.

New York

Reliability – N.Y has reliability performance mechanisms (RPM's) with set targets for CAIDI and SAIFI (both without major storms) for each utility and negative revenue adjustments if these annual targets are not met. The Commission issues a report summarizing all reports. Emergency and storm response times are also looked at when these events occur.

Performance incentives – have been negotiated within the context of individual utility rate cases. Incentives are different for each of the 9 (gas and electric) utilities. These are customer complaint performance mechanisms with negative revenue adjustments associated with poor performance.

** Both reliability and customer complaint mechanisms are reviewed and adjusted during each rate case.

The RPM contains nine performance metrics:

1. Threshold Standards consisting of measures of service outage frequency [System Average Interruption Frequency Index("SAIFI")] and duration [Customer Average Interruption Duration Index ("CAIDI")] on Con Edison's non-network ("radial") distribution system, and measures of service outage frequency (number of outages per 1,000 customers and feeder open-automatics during summertime) and average outage duration (CAIDI) on Con Edison's network distribution system
2. Major Outage metric
3. Program Standard for repairs to damaged poles
4. Program Standard for the removal of shunts
5. Program Standard for the repair of no current street lights and traffic signals
6. Program Standard for the replacement of over-duty circuit breakers
7. Remote Monitoring System metric.
8. Restoration Performance metric
9. Intrusion Detection system.

Washington State

WAC 480-100-398 Electric service reliability reports.

The electric utility must file an electric service reliability report with the commission at least once a year. The report must meet the following conditions:

(1) The report must be consistent with the electric service reliability monitoring and reporting plan filed under WAC 480-100-393. As set forth in the plan, in an identified year, baseline reliability statistics must be established and reported. In subsequent years, new reliability statistics must be compared to the baseline reliability statistics and to reliability statistics from all intervening years. The utility must maintain historical reliability information necessary to show trends for a minimum of seven years.

(2) The report must address any changes that the utility may make in the collection of data and calculation of reliability information after initial baselines are set. The utility must explain why the changes occurred and explain how the change is expected to affect comparisons of the newer and older information. Additionally, to the extent practical, the utility must quantify the effect of such changes on the comparability of new reliability statistics to baseline reliability statistics.

(3) The report must identify the utility's geographic areas of greatest reliability concern, explain their causes, and explain how the utility plans to address them.

(4) The report must identify the total number of customer complaints about reliability and power quality made to the utility during the year, and must distinguish between complaints about sustained interruptions and power quality. The report must also identify complaints that were made about major events.

Wisconsin[12]- PSC 113.0604 Annual report.

(1) Beginning on May 1, 2001 and by May 1 of every year thereafter, each electric utility with 100,000 customers or more, shall file with the commission a report summarizing various measures of reliability. The report shall include at least the following information: (2) An overall assessment of the reliability performance include the aggregate SAIFI, SAIDI and CAIDI indices by system and each operating area, as applicable; a list of the worst-performing circuits based on SAIFI, SAIDI and CAIDI indexes, for the calendar year; a report on the accomplishment of the improvements proposed in prior reports for which completion has not been previously reported; and numerous other requirements.

[12] Source: https://docs.legis.wisconsin.gov/code/admin_code/psc/113

MI – R 460.744 Penalty for failure to restore service after an interruption (any condition)

California PG&E Safety Net Program (not statewide):

- The Storm Inconvenience Payment provision of the Safety Net Program applies to residential customers only (rate schedules E-1, E-6, E-7, E-8, E-9, EA-7, EM, ES, ESR, and ET); customers also may be enrolled in programs such as CARE and medical baseline.
- Businesses, agricultural accounts, multi-family building common areas, streetlights, and all other customers other than residential customers are ineligible for Storm Inconvenience Payments.
- Storm Inconvenience Payments will not be issued to customers in areas where access to PG&E's electric facilities was blocked (mud slides, road closures or other access issues).
- The outage must have occurred during a major weather-related event that caused significant damage to PG&E's electric distribution system. (Customers who experience an extended outage of 24 hours or longer not related to a storm or severe event, may be eligible for a payment under the Service Guarantee Program.)
- The outage must have lasted more that 48 hours.
- Storm Inconvenience Payments are in increments of $25 ($100 maximum per event). Payment levels are based on the length of the customer's outage:
  - 48 to 72 hours $25
  - 72 to 96 hours $50
  - 96 to 120 hours $75
  - 120 hours or more $100
- Both bundled-service and direct-access residential customers qualify for Storm Inconvenience Payments.
- Storm Inconvenience Payments will be issued to the customer of record.
- A customer with multiple residential services such as a primary residence and a vacation home is eligible for Storm Inconvenience Payments at each location where there was a storm-related outage of more than 48 hours.
- Customers must have an open account (service agreement) in good standing at the time of the outage and at the time payment is issued (generally 45 to 60 days after the event).
- For master-metered accounts such as mobile home parks, the customer of record will receive the Storm Inconvenience Payment.

Source: https://www.pge.com/mybusiness/customerservice/energystatus/outagecompensation/

Illinois

- Under Illinois' Public Utilities Act, power companies are subject to pay for damages — such as spoiled food or damage to property and vehicles — when 30,000 or more customers lose power for four or more hours.

- But, at the same time, the statute provides utility with a waiver against claims stemming from things it can't control. They include "unpreventable damage due to weather events or conditions."

Indiana

- 170 IAC 4-1-23 Interruptions of service; timing; records
    - In general utilities are expected to restore service ASAP, but there are no penalties for extended outages. Commission reviews after the storm is over and makes recommendations.

Massachusetts:

(2) Penalties. (a) If after investigation the Department finds a violation of the standards established in 220 CMR 19.03, the Department shall levy a penalty not to exceed $250,000 for each violation for each day that the violation of the Department's standards persists; provided, however, that the maximum penalty shall not exceed $20,000,000 for any related series of violations. In determining the amount of the penalty, the Department shall consider, among other factors, the following: 1. the gravity of the violation; 2. the appropriateness of the penalty to the size of the Company; 3. the good faith of the Company in attempting to achieve compliance; and 4. the degree of control that the Company had over the circumstances that led to the violation. (b) Any penalty levied by the Department against a Company for any violation of the Department's standards established in 220 CMR 19.03 shall be credited back to the Company's customers in a manner determined by the Department

(3) Recovery of Service Restoration Costs. If after investigation the Department finds that, as a result of the failure of the Company to implement its ERP, the length of the Service Interruptions or outages was materially longer than they would have been but for the Company's failure, the Department may deny the recovery of all, or any part of, the service restoration costs through distribution rates, commensurate with the degree and impact of the Service Interruptions or outages.

Minnesota[13] - No penalty found.

Ohio

- **<u>4901:1-10-30 Failures to comply with the rules or commission orders.</u>**
    - Any electric utility or CRES provider that fails to comply with the rules and standards in this chapter, or with any commission order, direction, or requirement promulgated

[13] Source: https://www.revisor.mn.gov/rules/7826/

thereunder, may be subject to any and all remedies available under the law, including but not limited to the following:

- Forfeiture to the state of not more than ten thousand dollars for each such failure, with each day's continuance of the violation being a separate offense.
- Corrective action to effectuate compliance.
- Restitution or damages to the customer/consumer.
- Enforcement of any rule in this chapter or commission order, direction or requirement promulgated thereunder, will be conducted in accordance with Chapter 4901:1-23 of the Administrative Code.

Washington

- Restore service within 24 hours of customer reporting an outage (excludes major storm events). The Company pays out or provides a bill credit of $50 to the customer for recognition of the inconvenience.

Wisconsin[14]- No penalty found.

[14] Source: https://docs.legis.wisconsin.gov/code/admin_code/psc/113

APPENDIX A: Annual Reporting Requirements by State

California

Reliability Standards

The five largest electric utilities annually report industry standard measures of the duration and frequency of outages in order to evaluate performance and identify problem divisions and circuits.

Annual Reliability Reports of the major electric utilities include the following information:

- Duration and frequency of sustained and momentary outages using SAIDI, SAIFI, and MAIFI, with and without excludable major events for the past 10 years.
- The top ten power outage events based on customer-minutes, excluding events such as weather, declared emergencies, or disasters affecting over 10% of the utility's customers.
- Circuits in which customers have experienced greater than twelve sustained outages in a reporting year.

System statistics are computed including transmission, substation, and distribution outages but exclude intentional outages for example for line maintenance. Some of the remaining outages such as storm damage are considered beyond control of the utilities. Statistics are reported both including and excluding the storm outage data.

- **SAIDI** (System Average Interruption Duration Index) is the system-wide total number of minutes per year of sustained outage per customer served.
- **SAIFI** (System Average Interruption Frequency Index) is how often the system-wide average customer was interrupted in the reporting year.
- **MAIFI** (Momentary Average Interruption Frequency Index) is the number of momentary outages per customer system-wide per year.

As used above sustained outages are defined as 5 minutes or longer and momentary outages are less than 5 minutes long.

Utilities must maintain this data for each circuit (a circuit serves roughly 2,000 customers) and make it available to any interested person on request. See Appendix A of D.96-09-045. The Commission also opened an Electric Reliability Reporting Rulemaking (R.14-12-014) on December 18, 2014, to revise reliability reporting requirements.

After Major Storms Utilities Must Restore Service in Less Than 12 Hours on Average

CAIDI was added to reports of Measured Events (an event affecting between 10% simultaneous and 40% cumulative of all customers). The Commission presumes utility performance is unreasonable when the total minutes of interruption during the event divided by the total interruptions exceeds 570. See D.00-05-022.

In addition to its annual system-wide report PG&E submits:

An annual division-level report per D.04-10-034 including SAIDI, SAIFI, MAIFI and CAIDI at all 18 division levels; and the same data for any division whenever the data varies by 10 percent or more from the five-year rolling average of reliability performance

Illinois

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 complies 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.

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.

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.

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.

Indiana

Each investor-owned electric utility (IOU) in Indiana is required to file a reliability report annually with the Indiana Utility Regulatory Commission (IURC) in compliance with 170 IAC 4-1-23(e).i

The utilities provide the following three reliability indices in their reports:

 System Average Interruption Frequency Index (SAIFI): the average number of interruptions per customer. It is calculated by dividing the total number of customer interruptions by the total number of customers.

 System Average Interruption Duration Index (SAIDI): the average minutes of interruption per customer. It is calculated by dividing the sum of all customer interruption durations (in minutes) by the total number of customers.

 Customer Average Interruption Duration Index (CAIDI): the average duration of interruptions or the time to restore service to interrupted customers. It is calculated by dividing SAIDI by SAIFI.

Each utility reports its reliability indices with and without major events (Major Event Days or MEDs). Major events are primarily storms or weather events that are more destructive than normal storm patterns (it could also include earth quakes, fires, and other disasters). It is important to note that the same definition of "major event" is not used by all utilities which makes comparisons more difficult. However, Indiana IOUs define a major event day (MED) using a standard provided by the Institute of Electrical and Electronics Engineers (IEEE Standard 1366). It involves the calculation of a threshold in terms of SAIDI minutes based on data from the previous five years. Any day the threshold is exceeded is a MED.
The provision of indices that exclude major events normalizes the data by eliminating interruptions over which the utilities have little or no control. In addition, there can be great variation in major events (e.g.,tornadoes, floods, and ice storms), the resulting damage, and the time necessary to make repairs.

Massachusetts

19.03: Performance Standards for Emergency Preparation and Restoration of Service (1) 220 CMR 19.03 sets forth the standards that shall apply to each Company's performance regarding:

Emergency Preparation. Each Company shall ensure that it is adequately and sufficiently prepared to restore service to its customers in a safe and reasonably prompt manner during an Emergency Event.

(a) For electric distribution companies, this shall include at a minimum, but not be limited to:

1. implementing all applicable components of the electric distribution company's ERP related to planning and preparation for Emergency Events;
2. conducting the following on at least an annual basis:
    a. meetings with state and local officials to ensure effective and efficient flow of information and substantial and frequent coordination between the Company and local public safety

officials, including coordination with local officials with respect to vegetation management; and
b. training and drills/exercises to ensure effective and efficient performance of personnel during Emergency Events, and to ensure that each Company has the ability to restore service to its customers in a safe and reasonably prompt manner. 3. maintaining updated lists of local elected and appointed officials, state and local public safety officials, Life Support Customers, and all internal personnel and external entities involved in the Company's restoration efforts

Restoration of Service. Each Company shall restore service to its customers in a safe and reasonably prompt manner during all Service Interruptions and outages. During an Emergency Event, this shall include at a minimum, but not be limited to, implementing all applicable components of the Company's ERP related to restoration of service.

Reporting. Each Company, as identified in 220 CMR 19.03(4)(a) through (d), shall comply with the following reporting requirements:

(a) Each electric distribution company shall submit a report with supporting documentation to the Department on its preparation for Emergency Events that details each meeting, training, and drill/exercise held pursuant to 220 CMR 19.03(2)(a)2.;
(b) During an Emergency Event, each Company shall provide periodic reports to the Department, appropriate regional Massachusetts Emergency Management Agency representatives and municipal emergency managers, or their designees, that contain detailed information related to emergency conditions and restoration performance for each affected city and town;
(c) Following an Emergency Event, each Company shall submit a detailed report with supporting documentation to the Department on its restoration performance, including lessons learned; and
(d) Before, during, and after an Emergency Event, electric distribution companies are required to track, maintain, and ensure accuracy of all required storm-related data.

19.04: **Emergency Response Plans**

(1) Each Company shall submit to the Department an ERP that shall be designed to achieve safe and reasonably prompt restoration of service associated with an Emergency Event. The ERP shall include, but not be limited to, the following:

(a) identification of management staff responsible for Company operations, including a description of their specific duties; identification of the number of workers available to respond within 24 hours of an Emergency Event; and an estimation of the number of crews and full-time equivalents available to respond within 24 hours of an Emergency Event;
(b) a communications process with customers that provides continuous access to staff assistance. A Company shall provide estimated times of restoration on a website. Such information shall be prominently displayed and updated at least three times per day. A Company shall also provide estimated times of restoration at least three times per day through at least one other form of media outreach, and when requested by customers via telephone.
(c) for electric distribution companies, procedures for maintaining an updated list of Life Support Customers, including a process to immediately update a

Company's Life Support Customer list when a customer notifies the Company of a medical need for electric service, communicating with Life Support Customers before, during and after an Emergency Event, providing information to public safety officials regarding the status of electric service to Life Support Customers' homes, and procedures for prioritizing power restoration to Life Support Customers;
(d) designation of staff to communicate with local officials, including public safety officials, relevant regulatory agencies, and designated Municipal Liaisons, and designation of staff to be posted at the Massachusetts Emergency Management Agency's emergency operations center;
(e) provisions regarding how the Company will assure the safety of its employees, contractors and the public;
(f) procedures for deploying Company and contractor crews, and crews acquired through Mutual Assistance Agreements to work assignment areas;
(g) identification of additional supplies and equipment needed during an emergency and the means of obtaining additional supplies and equipment; and
(h) designation of a continuously staffed call center in the Commonwealth of Massachusetts that is sufficiently staffed to handle all customer calls for service assistance for the duration of an Emergency Event or until full service is restored, whichever occurs first. A Company with a call center within 50 miles of its service area, in operation as of January 1, 2012, shall not be required to designate an additional call center as long as the call center continues in operation. If the call center is unable to operate during an Emergency Event, the Company shall use a call center within 50 miles of the Commonwealth of Massachusetts.

(2) The ERP shall set forth the content, format and timeline for each report that the Company shall submit to the Department pursuant to 220 CMR 19.03(4).

(3) Each Company, when implementing its ERP, shall designate an employee or employees to remain stationed at the Massachusetts Emergency Management Agency's emergency operations center for the length of the Emergency Event. The employee or employees shall coordinate communication efforts with designated local emergency management officials and other emergency management officials.

(4) Each Company, when implementing its ERP, shall designate an employee or employees to serve as Municipal Liaisons for each affected municipality within its service territory. The Company shall provide each Municipal Liaison with the necessary feeder map or maps outlining municipal substations and distribution networks and up-to-date customer outage reports at the time of the designation as Municipal Liaisons. The Company shall provide each Municipal Liaison with three times daily customer outage report updates for the Municipal Liaison's respective municipality. The Municipal Liaisons shall use the maps and outage reports to respond to inquiries from state and local officials and relevant regulatory agencies.

(5) Each Company shall file an ERP, which the Company has reviewed and updated within the previous 12 months, with the Department on or before May 15 each year, for review and th approval. The filing shall include a copy of all written Mutual Assistance Agreements into

which the Company has entered, and identify and describe any modifications to the ERP and Mutual Assistance Agreements. A Company that fails to timely file its ERP may be fined $500 for each day during which such failure continues. The fines levied by the Department shall be returned to ratepayers through distribution rates.

(6) Each Company shall file with the emergency management director of each municipality within its service territory a copy of its ERP and any updates. Failure of a Company to file the ERP with the emergency management director of each municipality in the Company's service territory shall result in a penalty of $500. The penalties levied by the Department shall be credited back to the Company's customers in a manner determined by the Department.

(7) A Company's ERP shall go into effect when filed with the Department, pending Department review and approval, and shall remain in effect until a new ERP is filed or the Department directs otherwise. After review of a Company's ERP, the Department may request that the Company amend the ERP. The Department may open an investigation of the Company's ERP. If, after hearings, the Department finds a material deficiency in the ERP, the Department may order the Company to make such modifications to the ERP that it deems reasonably necessary to remedy the deficiency.

(8) If a Company makes any updates or changes to its ERP between annual filings, it shall submit such changes to the Department as soon as possible. Such changes shall go into effect when filed with the Department, pending Department review and approval.

Minnesota

All electric utilities authorized to do business in Minnesota are required to file an annual data report pursuant to MN Rules Chapter 7610. This information will be used to identify emerging energy trends based on supply and demand, conservation and public health and safety factors, and to determine the level of statewide and service area needs.

The report forms are due July 1, each year. If you did not receive an emailed spreadsheet form to complete and submit, download the "Spreadsheet: Electric Utility Data Report" spreadsheet file from the list, to complete and submit your report. You can also download "Instructions: Electric Utility Data Report" to help you complete the spreadsheet. Then e-file the completed spreadsheet and any required attachments (if available in .xls, .xlsx, or .pdf format) by uploading the files to the docket number shown below. The actual Electric Utility Annual spreadsheet file should be e-filed, not a pdf version of the spreadsheet.

Reporting Period: preceding calendar year

CHAPTER 7826, ELECTRIC UTILITY STANDARDS

PUBLIC UTILITIES COMMISSION

Reporting requirements

7826.0400 ANNUAL SAFETY REPORT.

On or before April 1 of each year, each utility shall file a report on its safety performance during the last calendar year. This report shall include at least the following information:

A. summaries of all reports filed with the United States Occupational Safety and Health Administration and the Occupational Safety and Health Division of the Minnesota Department of Labor and Industry during the calendar year; and

B. a description of all incidents during the calendar year in which an injury requiring medical attention or property damage resulting in compensation occurred as a result of downed wires or other electrical system failures and all remedial action taken as a result of any injuries or property damage described.

7826.1400 REPORTING METER-READING PERFORMANCE.

The annual service quality report must include a detailed report on the utility's meter-reading performance, including, for each customer class and for each calendar month:

the number and percentage of customer meters read by utility personnel;

the number and percentage of customer meters self-read by customers;

the number and percentage of customer meters that have not been read by utility personnel for periods of six to 12 months and for periods of longer than 12 months, and an explanation as to why they have not been read; and

data on monthly meter-reading staffing levels, by work center or geographical area.

7826.1500 REPORTING INVOLUNTARY DISCONNECTIONS.

The annual service quality report must include a detailed report on involuntary disconnections of service, including, for each customer class and each calendar month:

the number of customers who received disconnection notices;

the number of customers who sought cold weather rule protection under Minnesota Statutes, sections 216B.096 and 216B.097, and the number who were granted cold weather rule protection;

the total number of customers whose service was disconnected involuntarily and the number of these customers restored to service within 24 hours; and
the number of disconnected customers restored to service by entering into a payment plan.

7826.1600 REPORTING SERVICE EXTENSION REQUEST RESPONSE TIMES.

The annual service quality report must include a report on service extension request response times, including, for each customer class and each calendar month:

the number of customers requesting service to a location not previously served by the utility and the intervals between the date service was installed and the later of the in-service date requested by the customer or the date the premises were ready for service; and

the number of customers requesting service to a location previously served by the utility, but not served at the time of the request, and the intervals between the date service was installed and the later of the in-service date requested by the customer or the date the premises were ready for service.

7826.1700 REPORTING CALL CENTER RESPONSE TIMES.

The annual service quality report must include a detailed report on call center response times, including calls to the business office and calls regarding service interruptions. The report must include a month-by-month breakdown of this information.

Also rules on reporting on persons granted and refused medical account status, number of customers required to pay a deposit to obtain service and number and types of complaints.

7826.2000 REPORTING CUSTOMER COMPLAINTS.

The annual service quality report must include a detailed report on complaints by customer class and calendar month, including at least the following information:

the number of complaints received;

the number and percentage of complaints alleging billing errors, inaccurate metering, wrongful disconnection, high bills, inadequate service, and the number involving service-extension intervals, service-restoration intervals, and any other identifiable subject matter involved in five percent or more of customer complaints;

the number and percentage of complaints resolved upon initial inquiry, within ten days, and longer than ten days;

the number and percentage of all complaints resolved by taking any of the following actions:

taking the action the customer requested;

taking an action the customer and the utility agree is an acceptable compromise;

providing the customer with information that demonstrates that the situation complained of is not reasonably within the control of the utility; or

refusing to take the action the customer requested; and the number of complaints forwarded to the utility by the commission's Consumer Affairs Office for further investigation and action.

7826.0700 REPORTING MAJOR SERVICE INTERRUPTIONS.

Subpart 1.

Contemporaneous reporting.

A utility shall promptly inform the commission's Consumer Affairs Office of any major service interruption. At that time, the utility shall provide the following information, to the extent known:

A. the location and cause of the interruption;
B. the number of customers affected;
C. the expected duration of the interruption; and
D. the utility's best estimate of when service will be restored, by geographical area.

Subp. 2.

Written report.

Within 30 days, a utility shall file a written report on any major service interruption in which ten percent or more of its Minnesota customers were out of service for 24 hours or more. This report must include at least a description of:

A. the steps the utility took to restore service; and
B. any operational changes the utility has made, is considering, or intends to make, to prevent similar interruptions in the future or to restore service more quickly in the future.

7826.0800 CUSTOMER NOTICE OF PLANNED SERVICE INTERRUPTIONS.

Utilities shall give customers the most effective actual notice possible of any planned service interruption expected to last longer than 20 minutes. For any planned interruption expected to exceed four hours, the utility shall provide, if feasible, mailed notice one week in advance and notice by telephone or door-to-door household visits 12 to 72 hours before the interruption. Planned service interruptions must be scheduled at times to minimize the inconvenience to customers. When planned service interruptions exceeding four hours are canceled, utilities shall notify, if feasible, the customers who received notice that service would be interrupted.

New Jersey

14:5-8.10 Establishment of Reliability Service Performance Level

(a) For each of an EDC's operating areas, the reliability performance level is established as follows:
1. The operating area's CAIDI benchmark standard is set at the five-year average CAIDI for the years 2010-2014;
2. The operating area's SAIFI benchmark standard is set at the five-year average SAIFI for the years 2010-2014;
3. The minimum reliability level for each operating area is attained when its annual CAIDI and SAIFI are no higher than the CAIDI and SAIFI five-year benchmark standard plus 1.5 standard deviations.
(b) When the CAIDI and SAIFI of an EDC or its operating area do not meet the minimum reliability performance level, further review, analysis, and corrective action are required.
(c) The minimum reliability performance level to be assigned to an EDC and/or its operating area shall be reviewed and may be adjusted by Board order for subsequent years after consideration of various factors, including:
1. A comparison of actual multi-year CAIDIs and SAIFIs;
2. Trends among indices;
3. The average high and low values of multi-year indices;
4. Local geography, weather and electric system design of an operating area;
5. The relative performance of an operating area in relation to other operating areas of a given EDC's franchise area;
6. A comparison of the performance of all operating areas of all EDCs; and
7. A comparison of the performance of the EDC to other states or industry statistics.

14:5-8.7 Quarterly Reporting

(a) On a quarterly basis, each EDC shall prepare and submit a report to the Board's Energy Division providing the following information regarding all outages experienced and recorded during each quarter (other than momentary outages as defined by IEEE 1366 and major events, which shall be excluded). Each quarterly report shall be due within 60 days of the end of the quarter.

1. The quarterly outage reports shall provide the following information:
i. Outage type (primary, secondary, or service line, specific equipment);
ii. Circuit ID and type;
iii. Source substation;
iv. Number of customers on the circuit;
v. The municipality where the outage occurred;
vi. Number of customers affected by this outage;
vii. Start date/time of the outage;

viii. Total duration of outage in minutes; and
ix. The cause of outage (for example, vegetation, equipment failure, outside influence).
2. Each EDC may use its own method for identifying the type of outage, provided that each type of outage is clearly described.
3. The EDC shall provide an explanatory summary of any unique circumstances or potential problems identified and include a glossary of terms.
4. All outage data shall be submitted in a Microsoft Office Excel spreadsheet file. The explanatory summary may be submitted in another electronic document format compatible with Microsoft Office or Adobe Acrobat.
(b) The EDCs shall provide an additional Microsoft Office Excel spreadsheet detailing substation outage information.
1. For each outage due to substation specific equipment, the report shall include the substation ID, duration of the outage, and the number of customers affected by each outage.
2. The EDCs shall provide an explanatory summary of any unique circumstances or potential problems identified. The summary analysis should highlight areas that the EDCs determine need to be addressed, such as reliability problems (local or systemic), equipment issues, mitigation plans, and plans to address high-outage areas.
3. The substation outage data shall be submitted in a Microsoft Office Excel spreadsheet file. The explanatory summary may be submitted in another electronic document format compatible with Microsoft Office or Adobe Acrobat.
(c) The quarterly reports shall be submitted in an electronic form, both in redacted and unredacted versions, in accordance with the Board's rules on confidential information at N.J.A.C. 14:1-12, to protect security sensitive and other confidential information, such as circuit ID, substation information, circuit type and circuit location other than municipality, and number of customers on the circuit.

14:5-8.8 Annual System Performance Report

(a) Each EDC shall submit to the Board an Annual System Performance Report by May 31 of each year. The EDC shall also submit a copy of the report to Rate Counsel at the same time, which may be submitted electronically, at the discretion of the EDC.
(b) The Annual Report shall include all of the following data:
1. The electric service reliability performance for the EDC's predefined operating areas in relation to their minimum reliability levels of SAIFI and CAIDI;
2. A summary value for each EDC's New Jersey service territory as a whole in relation to their minimum reliability levels for CAIDI and SAIFI;
3. A summary of the EDC's system performance for the calendar year prior to the submittal of the report, accompanied by a graph displaying the data visually;
4. A summary of the EDC's system performance for the 10 years prior to the submittal of the report, including the data for the previous calendar year, accompanied by a graph displaying the data visually;
5. Statistical tables and charts for EDC reliability performance in its New Jersey service territory and by each operating area;

6. Ten years of trends of CAIDI and SAIFI; and
7. Ten years of trends reflecting the major causes of interruptions.

(c) The Annual Report shall also include a summary of:

1. The EDC's reliability programs, including inspection and maintenance programs;
2. Changes and exceptions to the EDC's current program(s);
3. The EDC's new reliability program(s);
4. The EDC's poor performing circuit program including the methodology used for circuit identification and any appropriate corrective actions;
5. The EDC's power quality program;
6. The EDC's stray voltage program;
7. Technology initiatives to improve reliability;
8. The number of personnel (broken down by bargaining and non-bargaining unit) in each EDC's operating area(s) and a summary statement referencing each EDC's training program;
9. The vegetation management work and planned activities as required in N.J.A.C. 14:5-9.7; and
10. Hazard tree information as required in N.J.A.C. 14:5-8.6(d)3.

(d) An officer of the EDC shall certify to the accuracy of the data and analysis in the Annual Report, and that necessary maintenance programs and other actions are being performed and adequately funded and addressed in its business plans to help achieve the benchmark reliability levels and as a minimum to maintain the minimum reliability levels for each operating area.

(e) The Annual Report shall include a summary of each major event.

(f) In the event that an EDC's reliability performance in an operating area does not meet the minimum reliability level for the calendar year, the Annual Report shall include the following:

1. An analysis of the service interruption causes, patterns and trends;
2. A description of the corrective actions taken or to be taken by the EDC and the target dates by which the corrective action shall be completed; and
3. If no corrective actions are planned, an explanation shall be provided.

(g) Each EDC shall include in its Annual Report eight percent of its worst-performing circuits identified in each of its operating areas in N.J.A.C. 14:5-8.5(b) based on the reliability performance parameters in N.J.A.C. 14:5-8.5(a) and the corrective actions taken or to be taken.

1. The EDCs will list the circuits that were:
i. Addressed and the work completed to address them during the applicable performance year; and
ii. Identified at the end of the applicable performance year to be addressed in the next performance year.
2. The EDCs will implement mitigation for these circuits as soon as possible but not later than one year from submission of the annual report with the goal of improving the circuit's reliability performance metrics.
3. If an EDC contends that the mitigation work cannot be implemented within that timeframe, the EDC must provide a detailed explanation to the Board of the reasons.

(h) The Board may require EDCs to submit alternative reports covering a time period other than that covered by the Annual Report.

14:5-8.9 Major Event Report

(a) The EDC shall, within 15 business days after the end of a major event, submit a report to the Board, which shall include the following:
1. The date and time when the EDC's storm or major event center opened and closed;
2. The total number of customers out of service over the course of the major event over four hour intervals, identified by operating area or circuit area. For purposes of this count, the starting time shall be when the storm center opens and the ending time shall be when the storm center closes. Regardless of when the storm center is closed, the EDC shall report the date and time when the last customer affected by a major event is restored;
3. The number of trouble locations and classifications;
4. The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance;
5. A timeline profile of the number of company line crews, mutual aid crews, non-company contractor line and tree crews working on restoration activities during the duration of the major event; and
6. A timeline profile of the number of company crews sent to an affected operating area to assist in the restoration effort.
(b) The EDC shall continue to cooperate with any Board request for information before, during and after a major event.

New York

Reliability – N.Y has reliability performance mechanisms (RPM's) with set targets for CAIDI and SAIFI (both without major storms) for each utility and negative revenue adjustments if these annual targets are not met. The Commission issues a report summarizing all reports. Emergency and storm response times are also looked at when these events occur.

Performance incentives – have been negotiated within the context of individual utility rate cases. Incentives are different for each of the 9 (gas and electric) utilities. These are customer complaint performance mechanisms with negative revenue adjustments associated with poor performance.

** Both reliability and customer complaint mechanisms are reviewed and adjusted during each rate case.

The RPM contains nine performance metrics:

> 1. Threshold Standards consisting of measures of service outage frequency [System Average Interruption Frequency Index("SAIFI")] and duration [Customer Average Interruption Duration Index ("CAIDI")] on Con Edison's non-network ("radial") distribution system, and measures of service outage frequency (number of outages per

1,000 customers and feeder open-automatics during summertime) and average outage duration (CAIDI) on Con Edison's network distribution system
2. Major Outage metric
3. Program Standard for repairs to damaged poles
4. Program Standard for the removal of shunts
5. Program Standard for the repair of no current street lights and traffic signals
6. Program Standard for the replacement of over-duty circuit breakers
7. Remote Monitoring System metric.
8. Restoration Performance metric
9. Intrusion Detection system.

Ohio

4901:1-10-26 Annual system improvement plan report.

(A) Each electric utility and transmission owner shall report annually regarding its compliance with the minimum service quality, safety, and reliability requirements for noncompetitive retail electric services.

(B) Annual report. On or before March thirty-first of each year, each electric utility and transmission owner shall file with the commission an annual report for the previous calendar year by the utility's chief executive officer or other senior officer responsible for the service quality, safety, and reliability of the electric utility's and transmission owner's transmission and/or distribution service. The annual report shall include:

(1) A plan for investment in and improvements to the electric utility's or transmission owner's transmission and distribution facilities/equipment that will ensure high quality, safe, and reliable delivery of energy to customers and will provide the delivery reliability needed for fair and open competition. Each plan shall also contain the estimated cost of implementation and any changes to the plan from the previous annual report. Each plan shall:

(a) Cover all of the electric utility's service territory, and shall describe the relevant characteristics of the service territory including the following:

(i) The number of miles of overhead distribution lines.

(ii) The number of miles of underground distribution lines.

(iii) The number of miles of overhead transmission lines.

(iv) The number of miles of underground transmission lines.

(v) Any other notable characteristics.

(b) Cover a period of no less than three years following the year in which the report was filed.

(c) Provide a timetable for achievement of the plan's goals.

(d) List any quality, safety, and reliability complaints the electric utility or transmission owner received during the reporting period from other electric utilities, rural electric cooperatives, municipal electric utilities, and competitive retail electric suppliers, and shall report the specific actions the electric utility took to address these complaints.

(e) For transmission facilities within the commission's jurisdiction, list any electric reliability standards violations, regional transmission operator operating violations, transmission load relief, the top ten congestion facilities by hours of congestion occurring on the electric utility's and/or transmission owner's facilities, and a description of the relationship between the annual system improvement plan and the regional transmission operator's transmission expansion plan.

(f) Report all unresolved quality, safety, and reliability complaints and violations as described in paragraphs (B)(1)(d) and (B)(1)(e) of this rule that were carried over from the prior year, along with the reason the complaint or violation was not resolved.

(2) A report of the electric utility's or transmission owner's implementation of the plan that it filed pursuant to paragraph (B)(1) of this rule for the previous annual reporting period, including an identification of significant deviations from the goals of the previous plan and the reasons for the deviations.

(3) A report by service territory of the age, current condition, reliability and performance of the electric utility's and/or transmission owner's transmission and distribution facilities in Ohio. (In analyzing and reporting the age of the electric utility's and/or transmission owner's facilities and equipment, the electric utility and/or transmission owner 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 report shall include:

(a) A qualitative characterization of the condition of the electric utility's and/or transmission owner's system and an explanation of the criteria used in making the qualitative assessment.

(b) An overview of the number and substance of customers' safety and reliability complaints for the annual reporting period in each service territory.

(c) Each electric utility's or transmission owner's transmission capital and maintenance expenditures as follows:

(i) Total expenditures for the past year and the ratio of such expenditures to total transmission investment;

(ii) Reliability-specific budgeted vs. actual expenditures for the past year by budget category and total, and an explanation for any variance exceeding ten per cent; and

(iii) Budgeted reliability-specific expenditures for the current year by budget category and total.

(d) Each electric utility's distribution capital and maintenance expenditures as follows:

(i) Total expenditures for the past year and the ratio of such expenditures to total distribution investment;

(ii) Reliability-specific budgeted vs. actual expenditures for the past year by budget category and total, and an explanation for any variance exceeding ten per cent; and

(iii) Budgeted reliability-specific expenditures for the current year by budget category and total.

(e) The average remaining depreciation lives of the electric utility's and/or transmission owner's transmission and distribution facilities, expressed separately by facility type as a percentage of total depreciation lives.

(f) For each reporting period, provide a list and purpose of current inspection, maintenance, repair, and replacement programs required by paragraph (E) of rule 4901:1-10-27 of the Administrative Code that the electric utility and/or transmission owner's utilizes for quality, safe, and reliable service from its transmission, substation, and distribution facilities and/or equipment. This report shall include the following:

(i) The goals of each program and whether the electric utility's and/or transmission owner's annual goals for each program were achieved. If the goals were achieved, describe how they were achieved and to what extent, including numerical values and percentages in the description. If the goals were not achieved, describe the problems that prevented the achievement and the level of completion of each program, including numerical values and percentages.

(ii) A summary of the electric utility's and/or transmission owner's annual findings as a result of performing each program.

(iii) A summary of the remedial activity that has been or will be performed as a result of the program findings, and the actual and estimated completion dates for such remedial activity.

(iv) The electric utility's and/or transmission owner's plans and programs to prevent overloading or excessive loading of its transmission and distribution facilities and equipment.

(v) The electric utility's and/or transmission owner's actions to remedy overloading or excessive loading of its transmission and distribution facilities and equipment.

(vi) An identification of the programs that have been added, deleted, and/or modified from the previous reporting period in accordance with the requirements of paragraph (F) of rule 4901:1-10-27 of the Administrative Code.

(4) An identification of customer service interruptions that were due solely to the actions or in-actions of another electric utility, regional transmission entity, and/or a competitive retail electric supplier for the annual reporting period and the causes of these interruptions.

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Wisconsin

PSC 113.0603 Recording standards.

(1) AGGREGATE SYSTEM RELIABILITY PERFORMANCE. Each electric utility with 100,000 customers or more shall keep a record of the necessary interruption data and calculate the SAIFI, SAIDI and CAIDI indices of its system and of each operating area, if applicable, at the end of each calendar year for the previous 12-month period.

(2) INDIVIDUAL CIRCUIT RELIABILITY PERFORMANCE. Each utility also shall, at the end of each calendar year, calculate the SAIFI, SAIDI and CAIDI indices for each circuit in each operating area. Each circuit in each operating area shall then be listed in order separately according to its SAIFI index, its SAIDI index and also its CAIDI index, beginning with the highest values for each index.

(3) Utilities shall maintain as much information as feasible on momentary outages. Each utility shall keep an annual count of recloser operations, or equivalent information through application of monitoring technology.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0604 Annual report.

(1) Beginning on May 1, 2001 and by May 1 of every year thereafter, each electric utility with 100,000 customers or more, shall file with the commission a report summarizing various measures of reliability. The form of the report shall be subject to review and approval by the commission staff. Names and/or numbers used to identify operating areas or individual circuits may conform to the utility's practice, but should allow ready identification of the geographic location or the general area served. Electronic (computer) recording and reporting of the required data and information is encouraged. The report shall include at least the following information:

(2) **(a)** An overall assessment of the reliability performance including the aggregate SAIFI, SAIDI and CAIDI indices by system and each operating area, as applicable.

(b) A list of the worst-performing circuits based on SAIFI, SAIDI and CAIDI indexes, for the calendar year. This section of the report shall describe the actions that the utility has taken or will take to remedy the conditions responsible for each listed circuit's unacceptable performance. The action(s) taken or planned should be briefly described. Target dates for corrective action(s) shall be included in the report. When the utility determines that actions on its part are unwarranted, its report shall provide adequate justification for such a conclusion.

(c) Utilities that use or prefer alternative criteria for measuring individual circuit performance to those described in s. PSC 113.0603 and which are required by this section to submit an annual report of reliability data, shall submit their alternative listing of circuits along with the criteria used to rank circuit performance.

(d) A report on the accomplishment of the improvements proposed in prior reports for which completion has not been previously reported.

(e) A description of any new reliability or power quality programs and changes that are made to existing programs.

(f) A status report of any long range electric distribution plans.

(3) In addition to the information included in sub. (1), each utility shall report the following additional service quality information:

(a) Route miles of electric distribution line reconstructed during the year. Separate totals for single- and three-phase circuits shall be provided.

(b) Total route miles of electric distribution line in service at year's end, segregated by voltage level.

(c) Monthly average speed of answer, as defined in s. PSC 113.0503 (1)(b), for telephone calls received regarding emergencies, outages and customer billing problems.

(d) The average number of calendar days a utility takes to install and energize service to a customer site once it is ready to receive service. A separate average shall be calculated for each month, including all extensions energized during the calendar month.

(e) The total number of written and telephone customer complaints received in the areas of safety, customer billing, outages, power quality, customer property damage and other areas, by month filed.

(f) Total annual tree trimming budget and actual expenses.

PSC 113.0604(3)(g)**(g)** Total annual projected and actual miles of distribution line tree trimmed.

PSC 113.0609 Customer satisfaction surveys.

(1) Using methods approved by the commission, each municipally owned electric public utility and each investor-owned utility with a customer count of 20,000 or less, as directed by the commission where there is cause to do so, and each investor-owned electric public utility with a customer count greater than 20,000, on an annual basis, shall fund quantitative assessments, made by an independent entity, of the satisfaction of all customer classes with the services they have received from the utility. The results of these assessments shall be filed with the commission. The utility shall provide to the commission a detailed report of the information from any research it has conducted in the past year to help assess:

(a) The satisfaction of the utility's customers with the services they have received from the utility.

(b) The specific new services or alterations to existing services desired by customers.

(2) This information shall at a minimum include the following:

(a) A detailed description of the methods used to conduct the research and analyze the results.

(b) The results of the research, including mean scores for all variables studied, both for the study sample as a whole and for meaningful sample subgroups.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00; CR 02-027: am. (1) (intro.), Register December 2002 No. 564, eff. 1-1-03.

PSC 113.0610 Customers' complaints.

(1) Each utility shall investigate and keep a record of complaints received by it from its customers in regard to safety, service, or rates and the operation of its system with appropriate response times designated for critical safety and monetary loss situations. The record shall show the name and address of the complainant, the date and nature of the complaint, the priority assigned to the assistance and its disposition and the time and date thereof.

(2) Each utility also shall document all contacts and action relative to deferred payment agreements and disputes.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0608 Emergency response. Each utility with 25,000 customers or more shall establish procedures to record and monitor its response times for emergencies, such as calls for assistance from police, fire, emergency medical services officials and any calls or reports of wire contacts, dig-ins, wires down, utility facilities on fire, unauthorized entry into utility facilities, unsecured public access to energized equipment, or any similar activity on or near utility facilities constituting a hazardous condition or an immediate threat or danger to persons, customers' property, customers business operations or general property. In general, the records of these calls should include the date and time received; the identity (if known) of the caller; the identity of the person receiving the call; the location and nature of the problem, incident, or accident; the time the utility responder arrived at the location; the total time to respond; and the final disposition or resolution of the problem.

Note: It is recognized that strict compliance with this rule may be difficult during major system-wide or large area emergencies, for example, major wind or ice storms where many outage reports may also involve reports of “wires down." However, reasonable efforts should still be made to identify and give priority response to calls for assistance from police and fire officials who may be "first responders." This will allow these locations to be secured so the police or fire units can be released to pursue other duties.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0607 Appropriate inspection and maintenance: system reliability.

(1) PREVENTATIVE MAINTENANCE PLAN. Each utility or other person subject to this chapter, including persons who own electric generating facilities in this state who provide service to utilities with contracts of 5 years or more, shall develop and have in place its own preventative maintenance plan. This section is applicable to electric generating facilities as set forth at s. 196.491 (5) (a) 1., Stats. Each plan shall include, among other things, appropriate inspection, maintenance and replacement cycles where applicable for overhead and underground distribution plant, transmission, generation and substation facilities.

(2) CONTENTS OF THE PLAN.

(a) *Performance standard.* The preventative maintenance plan shall be designed to ensure high quality, safe and reliable service, considering: cost, geography, weather, applicable codes, national electric industry practices, sound engineering judgment and experience.

(b) *Elements of the plan.*

1. Inspection.

a. The plan under sub. (1) shall include a schedule for the periodic inspection of all facilities owned and operated by the utility and used to provide electric service to its customers. The plan under sub. (1) shall describe the method for inspection of each type of equipment as designated by the reporting utility. Checklist/report forms shall be included in the plan under sub. (1).

b. The plan under sub. (1) shall include guidelines for inspectors to determine the condition of a facility or piece of equipment.

2. Condition rating criteria. A rating criteria shall be established to grade the condition of a facility or piece of equipment. Rating criteria for generating facilities should conform to generator availability data system (GADS) requirements as reported to the national electric reliability council, or other accepted industry practices.

3. Corrective action schedule. The results of inspections, assessments and condition rating criteria shall be used to define the schedule for implementing maintenance on the facility or piece of equipment. The plan under sub. (1) shall describe how facilities or equipment corrective action schedules are added to the utility's budget.

4. Record keeping. Each utility shall maintain records to allow auditing of its preventative maintenance plan implementation. The records shall include inspection dates, condition rating, schedule for repair (if applicable) and the date of completion of the repair. Inspection and repair records shall be retained for a minimum of ten years.

5. Filing of plans. Each utility, as well as the transmission company created by s. 196.485, Stats., shall file a plan in compliance with this rule within 180 days of acceptance of the rules or, in the alternative, within 180 days after the utility transmission company or other person subject to this chapter begins operation of a facility subject to this chapter.

6. Reporting requirements. Each utility shall provide a periodic report to the commission showing compliance with its preventative maintenance plan. The report shall include a list of inspected circuits and facilities, the condition of facilities according to established rating criteria, schedules established and success at meeting the established schedules. For generation facilities, the report shall include a summary of each generating unit's operating performance statistics based on the utility's GADS data, or other accepted industry data convention. Reported generating unit performance data shall include net dependable capacity, capacity factor, forced outage rate, scheduled outage factor, primary fuel and production technology type. The commission shall establish a periodic report schedule for each utility of at least once every 2 years.

7. Exchange of information. At least annually, utilities shall exchange planned outage information for the coming year for expected maintenance and other outages of generators of 50 MW or more and transmissions lines of 100 kV and higher voltage. Utilities shall also supply the same information for nonutility generators of 50 MW or more in their control areas. Utilities shall exchange updates of such information as soon as reasonably practicable when such updated information becomes known.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00; CR 02-027: am. (2) (a), (b) 1. a. and b. 2. and 3., and (2) (b) 6., Register December 2002 No. 564, eff. 1-1-03.

PSC 113.0606 Interruptions of service.

(1) Each utility shall keep a record of all interruptions to service affecting the entire distribution system of any single community or an important division of a community and include in such record the location, date and time of interruption, the duration, the approximate number of customers affected, the circuit or circuits involved and, when known, the cause of each interruption.

(2) When complete distribution systems or portions of communities have service furnished from unattended stations, these records shall be kept to the extent practicable. The record of unattended stations shall show interruptions which require attention to restore service, with the estimated time of interruption. Breaker or fuse operations affecting service should also be indicated even though duration of interruption may not be known.

(3) Each utility shall notify the commission of any event described in par. (a), (b), (c), (d) or (e) involving bulk power supply facilities (any generating unit or electric facilities operating at a nominal voltage of 69 kV or higher):

(a) Any interruption or loss of service to customers for 15 minutes or more to aggregate firm loads in excess of 200,000 kW. Such notification shall be made by telephone as soon as practicable without unduly interfering with service restoration and, in any event, within one hour after beginning of the interruption. A confirming written report shall be submitted within 2 weeks.

(b) Any interruption or loss of service to customers for 15 minutes or more to aggregate firm loads exceeding the lesser of 100,000 kW or half of the current annual system peak load and not required to be reported under par. (a). Such notification shall be made by telephone no later than the beginning of the commission's next regular work day after the interruption occurred. A confirming written report shall be submitted within 2 weeks.

(c) Any decision to issue a public request for reduction in use of electricity. Notification of such decision shall be made by telephone at the time of issuing such request. A confirming written report shall be submitted within 2 weeks.

(d) Any action to reduce firm customer loads by reduction of voltage for reasons of maintaining adequacy of bulk electric power supply. Notification of such action shall be made by telephone at the time of taking such action. A confirming written report shall be submitted within 2 weeks.

(e) Any action to reduce firm customer loads by manual switching, operation of automatic load shedding devices, or any other means for reasons of maintaining adequacy of bulk electric power supply. Notification of such action shall be made by telephone at the time of taking such action.

(4) Each utility shall notify the commission of service interruptions not involving bulk power supply facilities as follows:

(a) Interruptions of 60 minutes or more to an entire distribution substation bus or entire feeder serving either 500 or more customers or entire cities or villages having 200 or more customers shall be reported within 2 weeks by a written report.

(5) The written reports of subs. (3) and (4) shall include the date, time, duration, general location, approximate number of customers affected, identification of circuit or circuits involved and, when known, the cause of the interruption. When extensive interruptions occur, as from a storm, a narrative report including the extent of the interruptions and system damage, estimated number of customers affected and a list of entire communities interrupted may be submitted in lieu of reports of individual interruptions.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0503 Telephone answering time.

(1) In this section:

(a) "Computerized call center system" means a system where an automatic call distributor is used to manage incoming calls and to place calls in a queue and that has the capability to generate significant statistical information.

(b) "Speed of answer" means the amount of time it takes for a call to be connected to either a live agent or an automated system that is ready to assist the customer and is measured beginning from the point when the call is first queued to be connected.

(2)

(a) A utility or its agent shall maintain sufficient employees and equipment to achieve an average speed of answer of not more than 90 seconds. The average speed of answer shall be determined by summing the total queuing time and dividing by the total number of customer calls handled by automated systems. A utility or its agent shall calculate this average speed of answer on a monthly basis, including customer service calls, outage calls and emergency calls.

(b) A utility or its agent shall maintain sufficient employees to achieve an average speed of live response of not more than 90 seconds. The average speed of live response shall be determined by summing the total time from indication of request for live response and divided by the total number of calls answered by a live agent. A utility or its agent shall calculate this average speed of answer on a monthly basis, including customer service calls, outage calls and emergency calls.

(3) A utility or its agent shall give emergency calls the highest priority and shall be generally available for all calls and must provide customers with the option of selecting a live agent contact among those selections presented by any computerized call center system.

(4) A utility or its agent shall maintain average speed of answer data in a manner set forth by the commission and must provide customers with the option of selecting a live agent contact among those selections presented by any computerized call center system.

(5) The requirements of subs. (2) to (4) do not apply in either of the following circumstances:

(a) To a utility or its agent that do not use a computerized call center system.

(b) During natural disasters, severe weather, or other events beyond the utility's control that adversely impact the utility's telephone answering capabilities.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0512 Identification of potential power line natural hazards.

(1) IDENTIFICATION OF POTENTIAL POWER LINE NATURAL HAZARDS. Utilities shall conduct a program of identification of potential power line natural hazards in accordance with training approved by the commission.

(2) INSPECTION TO IDENTIFY POTENTIAL POWER LINE NATURAL HAZARDS.

(a) *Inspection.* The utilities shall conduct inspections of its operations, including its transmission and distribution lines and facility rights-of-way, every 3 to 8 years and within 60 days of an order for inspection issued by the commission.

(b) *Request for inspection.* Any person, organization or agency may request the utility to make an inspection for potential power line natural hazards and the commission on its own motion, may order the utility to inspect its transmission and distribution lines and rights-of-way for potential power line natural hazards. The utility shall make such inspection upon a showing that potential power line natural hazards may exist.

(3) RESPONSE TO IDENTIFICATION OF POTENTIAL POWER LINE NATURAL HAZARDS. Upon identifying a potential power line natural hazard, the utility shall take action to eliminate the hazard to the power line. The utility shall make a reasonable effort to notify the owner or other individual with authority, to trim or remove the tree of the potential danger and method by which the danger may be minimized or removed. Nothing in this section shall preclude the utility's obligation to immediately remove the hazard, as required by ch. PSC 114.

Note: Section 26.14 (9) (b), Stats., subjects a person to liability for the cost of suppressing a forest fire if the forest fire is intentionally or negligently set and allowed to escape. A utility not inspecting its lines or operations to identify, trim or remove hazardous trees consistent with these rules may be found negligent and, therefore, responsible for payment of forest fire suppression costs resulting from a forest fire caused by a tree or branch breaking or damaging a line or equipment. A utility complying with these rules, is not expected to be responsible for costs associated with forest fire suppression under s. 26.14 (9) (b), Stats. If a utility complying with this section is not authorized to trim or remove a tree it identifies as hazardous, consistent with the training required by it; a landowner notified of the potential danger or damage that may be caused to the transmission or distribution line or operation, might be found later to have been negligent and responsible for the costs of setting and allowing a forest fire to escape; however, the agency seeking reimbursement for the costs has the burden of proving that the landowner is responsible. The goal of this effort is to reduce the likelihood of outages and forest fires, thereby reducing the likelihood that anyone is responsible for forest fire suppression costs.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

PSC 113.0601 Standards for electric service reliability.

(1) The purpose of ss. PSC 113.0601 to 113.0605 is to establish standards and reporting requirements to provide consumers, the commission and electric utilities with a uniform method to monitor the reliability of electric service delivered in an electric utility's operating area. These rules adopt definitions and requirements for maintenance of interruption data, retention of records and report filing, in addition to those in the other sections of subch. IV.

(2) In general, utilities are expected to provide sufficient resources to assure reasonably adequate and reliable service to all of their customers under normal operating conditions. These standards establish the reliability of service on an annual basis under all operating conditions, including during major storms, major catastrophic events and police actions. A utility may supply supplemental reliability statistics excluding the aforementioned situations (in addition to the statistics with those events included) with a written justification for exclusion.

(3) The commission will use this information to measure and monitor overall reliability performance of individual utilities. The commission may review data by utility, trends of measures over time and comparison of measures between and among utilities of similar characteristics. Where necessary, the information may be used by the commission to take enforcement actions through other proceedings to maintain or improve reliability performance and to assure customers are receiving reasonably adequate service.

History: Cr. Register, July, 2000, No. 535, eff. 8-1-00.

Washington State

WAC 480-100-398 Electric service reliability reports.

The electric utility must file an electric service reliability report with the commission at least once a year. The report must meet the following conditions:

(1) The report must be consistent with the electric service reliability monitoring and reporting plan filed under WAC 480-100-393. As set forth in the plan, in an identified year, baseline reliability statistics must be established and reported. In subsequent years, new reliability statistics must be compared to the baseline reliability statistics and to reliability statistics from all intervening years. The utility must maintain historical reliability information necessary to show trends for a minimum of seven years.

(2) The report must address any changes that the utility may make in the collection of data and calculation of reliability information after initial baselines are set. The utility must explain why the changes occurred and explain how the change is expected to affect comparisons of the newer and older information. Additionally, to the extent practical, the utility must quantify the effect of such changes on the comparability of new reliability statistics to baseline reliability statistics.

(3) The report must identify the utility's geographic areas of greatest reliability concern, explain their causes, and explain how the utility plans to address them.

(4) The report must identify the total number of customer complaints about reliability and power quality made to the utility during the year, and must distinguish between complaints about sustained interruptions and power quality. The report must also identify complaints that were made about major events.