Making the Most of Michigan's Energy Future

Grid Security and Reliability Standards Workgroup

Staff Final Report: Technical Standards for Electric Service

U-20630

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Statewide Energy Assessment, MI Power Grid, and Workgroup Formation

Following a series of energy events that occurred on January 29 through February 1, 2019, Governor Gretchen Whitmer requested the Michigan Public Service Commission (MPSC or Commission) review the state's energy supply and preparedness for emergency situations.[1] The review was subsequently ordered by the Commission on February 7, 2019, in Docket U-20464,[2] which, after an initial draft and a public comment period, resulted in the final Statewide Energy Assessment (SEA) issued September 11, 2019.[3] The final assessment provided 37 MPSC jurisdictional and 15 non-MPSC jurisdictional recommendations for improving the safety and reliability of Michigan's energy infrastructure. In recognition of some key recommendations with potential for the most immediate and impactful improvements, the Commission provided direction for additional work, including the opening of dockets to establish workgroups charged with reviewing two existing rulesets: Service Quality and Reliability Standards for Electric Distribution Systems[4] ("Service Quality," Docket U-20629); and Technical Standards for Electric Service[5] ("Technical Standards," Docket U-20630).

Specifically, the Commission provided the following charge:

> These workgroups will look to other states for best practices and optimal standards regarding the rule sets. In particular, the workgroups will consider current and probable future technological advances in electric distribution systems and electric service, and will recommend changes to the standards in keeping with those advances. While the workgroups will not engage in official rule-making activities, the Commission's goal is that input from the workgroups will provide a foundation for potential future rule changes that are flexible and responsive to changing technology and that ensure safe, reliable electric service.[6]

On October 17, 2019, approximately one month after the Commission created the Service Quality and Technical Standards workgroups, the Commission launched MI Power Grid in

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[1] https://www.michigan.gov/documents/whitmer/Letter_to_the_Michigan_Public_Service_Commission_645317_7.pdf
[2] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000003iBJFAA2
[3] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000005XrEbAAK
[4] https://www.michigan.gov/documents/mpsc/Service_Quality_Standards_672262_7.pdf
[5] https://www.michigan.gov/documents/mpsc/Technical_Standards_672264_7.pdf
[6] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000005XvTUAA0

collaboration with Governor Whitmer.[7] MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating emerging technologies; and optimizing grid investments and performance.[8]

Upon the creation of MI Power Grid, the nascent Service Quality and Technical Standards workgroups were combined and rebranded as the Grid Security and Reliability Standards Workgroup (Workgroup)[9] and incorporated into MI Power Grid under the initiative's Optimizing Grid Investments and Performance core area. MI Power Grid workgroups, such as the Grid Security and Reliability Standards Workgroup, are formed and led by MPSC Staff (Staff), and they seek to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. This report highlights the Grid Security and Reliability Standards Workgroup's activities and initial findings pertaining to the Technical Standards ruleset.[10]

Stakeholder Process

Staff launched a stakeholder process to leverage industry and other stakeholder expertise as the MPSC revises the Technical Standards. Staff's initial focus was to solicit participation in the Grid Security and Reliability Standards Workgroup and encourage interested parties to sign up for the listserv. The listserv continues to be a tool used to inform interested parties of upcoming meetings, Workgroup-related decisions, and how to participate in future Workgroup activities. After a period of dedicated outreach to garner interest, stakeholder meetings were held each month from December 2019 to March 2020 to identify issues with the current rules and discuss proposals to resolve them in a transparent manner. Most Workgroup materials, including agendas, presentations, and recordings, are available on the Grid Security and Reliability

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[7] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000077Gq4AAE

[8] The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid

[9] In this report, "Workgroup" refers specifically to the Grid Security and Reliability Standards Workgroup, while "workgroup" refers to any predecessor or affiliated workgroup.

[10] A separate report detailing the Workgroup's efforts and findings pertaining to the Service Quality ruleset is provided contemporaneously in Docket U-20629.

Standards webpage.[11] After each meeting, stakeholders were asked to submit comments to the docket about any changes they would like to see made to the Technical Standards or to respond to others' proposals, including those made by Staff. Stakeholders providing comments included DTE Electric (DTE), Consumers Energy (Consumers), Indiana Michigan Power (I&M), Michigan Electric Cooperative Association (MECA), Association of Businesses Advocating Tariff Equity (ABATE), Michigan Electric and Gas Association (MEGA), and the Citizens Utility Board of Michigan (CUB).

Stakeholder Meeting #1 – December 3, 2019: During the first stakeholder meeting, Staff presented an overview of the orders in Dockets U-20464 and U-20630, the Technical Standards, the Workgroup's webpage and listserv, and a Staff proposal for areas of concentration within the rules. The meeting concluded with Staff asking stakeholders to provide feedback on the Staff proposal, and for utilities to provide a breakdown of existing meter types (i.e. electro-mechanical vs solid state) and expected date to complete conversion to smart meters.

Stakeholder Meeting #2 – January 8, 2020: At the second stakeholder meeting, Staff summarized feedback from the first meeting, discussed the findings of Staff's multi-state review, and provided an overview of the Staff's proposed Cybersecurity Program rule. The meeting also featured a presentation from Public Sector Consultants outlining the findings of their multi-state research efforts. Both Staff and Public Sector Consultants' multi-state reviews are discussed in more detail below. Staff concluded the meeting with a preliminary list of Workgroup focus areas, based on Staff and stakeholder proposals, to help guide the Workgroup's efforts moving forward. At the close of the meeting, Staff requested stakeholder feedback regarding specific rule language recommendations, additional focus areas that have not been captured by Staff, and any other information that may be pertinent to the Workgroup's efforts.

Stakeholder Meeting #3 – February 12, 2020: At the February meeting, Staff summarized stakeholder feedback from the second meeting, provided a brief update on Staff's proposed Cybersecurity Program rule, and presented an updated list of focus areas. At Staff's request, Joseph Eto from Lawrence Berkeley National Laboratory[12] provided a technical presentation on vegetation management practices, vegetation management reporting, certain electric-sector definitions, and a list of considerations for the Workgroup moving forward. The meeting concluded with Staff asking stakeholders to provide feedback pertaining to the Joseph Eto

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[11] https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593_95590_95596_95597-508672--,00.html

[12] Lawrence Berkeley National Laboratory is a multi-program science lab supported by the U.S. Department of Energy and managed by the University of California.

presentation, updated focus areas, utility company industrial customer outage analysis processes, Michigan Occupational Safety and Health Administration (MIOSHA) reporting, and utility company emergency response plans.

<u>Stakeholder Meeting #4 – March 12, 2020</u>: Prior to the fourth stakeholder meeting, and based on Staff and stakeholder feedback, the list of focus areas was pared down to ten distinct issues the Workgroup sought to address in its recommended revisions to the Technical Standards. Staff discussed proposals related to three of these issues: emergency reporting, vegetation management, and standard frequency. The meeting concluded with Staff asking for feedback on the ten identified issues and to solicit proposals to address them.

Multi-State Reviews

The Commission order in Docket U-20630 directed the Technical Standards workgroup "to look to other states for best practices and optimal standards" to improve the Technical Standards. In response, two such reviews were conducted; one by Staff and another by Public Sector Consultants on behalf of a group of Michigan utilities. What follows is a synopsis of those two efforts.

Staff Review

Staff performed benchmarking research involving 10 states, which are shown in Table 1, to evaluate how Michigan's requirements compare to those of other states. Given the abundance of information available, Staff decided to limit the information gathered to Staff's areas of interest at the time: identifying the main elements of "Technical Standards," meter testing and accuracy requirements, cybersecurity requirements, how technological advancements are being incorporated into standards, and certain specific operations and maintenance (O&M) requirements, such as preventative maintenance and vegetation management.

Table 1: Staff Benchmarking States – Technical Standards

California	New Jersey
Illinois	New York
Indiana	Ohio
Massachusetts	Washington
Minnesota	Wisconsin

The selection methodology considered three main criteria: those states that are precedent setting; located in the Midwest; or experience extreme weather events. States experiencing extreme weather events, even when such events differ from those in Michigan, inform the Workgroup of how other states implement reliability and resiliency requirements given extreme weather events. The findings were shared in Staff's presentation to the Workgroup during the January 8, 2020 meeting and highlighted various conclusions, including:

- States have minimal to no cybersecurity requirements,

- States have more prescriptive vegetation management requirements than Michigan,
- The National Electrical Safety Code (NESC) is incorporated for design and installation of distribution systems, and
- State preventative maintenance requirements are generally not prescriptive.

Public Sector Consultants Review

To assist in the gathering of best practices in other states, three stakeholders – DTE, Consumers, and MEGA – hired Public Sector Consultants to perform a benchmarking project to review service quality, reliability, and technical standards for 25 states, including each of the 10 states included in Staff's research, and compare the rules in those states to the rules in Michigan. Some of the key findings of the report[13] include the following:

- Michigan is one of the first states to have requirements related to cybersecurity reporting,
- There are notable differences in how states establish meter requirements,
- States maintain billing adjustment standards with similar provisions as Michigan,
- Michigan has a higher level of detail for extension of facilities (Rule 411) than any other reviewed state, and
- Michigan's line clearance standard is less detailed than other states and references the NESC in defining vegetation management practices.

Identified Issues

The Workgroup meetings and benchmarking efforts of Staff and Public Sector Consultants were used to assist Staff in identifying issues that would be used to guide the Workgroup and subgroup efforts in updating the Technical Standards. A list of 10 issues were identified. Below is a brief description of each issue, Staff proposal, a brief description of known principal points of disagreement, and the issue's status. These can also be reviewed on the Grid Security and Reliability Standards webpage under "Related Documents."

1. Billing Rule Adjustments

Soon after the order was issued in Docket U-20630, Staff within the Compliance and Investigation Section and Electric Operations Section began discussing whether any rules in the Technical Standards would be better suited for inclusion in the Customer Standards and Billing

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[13] https://www.michigan.gov/documents/mpsc/PSC_Standards_Benchmarking_Report_02142020_681539_7.pdf

Practices for Electric and Natural Gas Service ruleset (Billing Rules), given the rulesets' respective scopes. Staff argues that the metering inaccuracies and billing adjustments sections are improperly located in the Technical Standards and should be moved to the Billing Rules.

Staff proposal

Transfer the applicable sections from the Technical Standards to the Billing Rules and update certain elements of the Technical Standards to improve consistency between the two rulesets.

Principal points of disagreement

None.

Status

Complete. The proposed redlines are provided in Appendix A recommending 1) Rule 460.3309 entitled "Metering inaccuracies; billing adjustments" be eliminated from the Technical Standards in its entirety and moved to the Billing Rules and 2) Rule 460.3303(c) entitled "Meter reading data" be amended to be consistent with the Billing Rule language in Rule 460.113(7).

2. Definitions

The Technical Standards contain words and phrases that are not clearly defined, which leads to a lack of clarity and consistency.

Staff proposal

Define terms and phrases in the Technical Standards including, but not limited to "sustained interruption," "major interruption," "planned interruption," "RTO," "serious injury," and "AMI" or "solid state meter."

Principal points of disagreement

Although there were various proposed definitions and comments regarding specific language to be included, there is a consensus that the aforementioned terms are necessary to define. In addition, using definitions from well-known, credible sources and consistently applying terms or phrases between the Technical Standards and the Service Quality rules is desired. Staff's proposed definition of "major interruption" is Michigan-specific and stakeholder comments suggest using the definition of "major event day" from IEEE-1366 while Staff opines that a Michigan-specific definition is necessary and must align with the current outage reporting procedures. Initially, there were discussions surrounding the need for clarity to accident reporting under Rule 460.3804. Workgroup participants submitted proposals to establish one rule for employee accidents and a separate rule for non-employee accidents to ensure that the Commission is provided with the electric utilities' awareness of non-employee accidents. Staff later clarified during a Workgroup meeting that Rule 460.3804 applies to both employee and non-employee accidents and utility companies shall report accordingly.

Status

Complete. The proposed redline definitions of “major interruption”, “planned interruption,” “regional transmission organization,” “serious injury”, “service point”, and “sustained interruption” are provided in Rule 460.3102, entitled “Definitions,” and found in Appendix A of this report. Definitions for “cooperative electric utility” and “electric utility” are also proposed additions and are described in further detail under issue #10 below. Staff recommends a Michigan-specific definition of “major interruption” addressing 1) outages caused by weather such as wind, lightning, and ice storms; and 2) electrical system component failures resulting in localized outages within utility company service territories. Given the variations in number of customers and size of service territories within the state, the definition is structured to include separate minimum reporting thresholds to define when notifications are required as prescribed in R 460.3705(4) given two separate customer classifications - one million or more customers and less than one million customers. The definition of “major interruption” was developed by Staff after reviewing the internal outage notification procedures and the “normal”, “gray sky”, and “catastrophic” conditions within the Service Quality rules and provides language to accommodate instances where the Commission may order reporting otherwise. The definition of “planned interruption” was derived from IEEE-1366, “regional transmission organization” from the Federal Energy Regulatory Commission (FERC), “serious injury” from the comments received from the various Workgroup meetings, “service point” from the NESC, and “sustained interruption” is aligned with the IEEE-1366 definition and the definition in the Service Quality ruleset. The proposed definition of “serious injury” is generally aligned with what is used by MIOSHA for injury reporting and the Pipeline and Hazardous Materials Safety Administration (PHMSA) for accident reporting with the incorporation of “in-patient hospitalization.” The “serious injury” definition also provides needed clarity to support Staff’s position that Rule 460.3804 applies to notifications involving both employees and non-employees. Staff does not recommend a definition for “AMI” to be included in the metering definitions as initially proposed. Staff opines that the definition of “solid state meter” effectively encompasses modern meters in the system, and a definition of “AMI” is not necessary to clarify the requirements outlined in the Technical Standards.

3. Emergency Reporting

The Energy Security and Electric Operations Staff do not have immediate access to utility company processes related to emergency situations such as storms. A reporting requirement would provide improved transparency between the utilities and Staff who perform emergency-related functions.

Staff proposal

Incorporate an Emergency Response Plan (ERP) filing requirement into the reporting section of the rules to allow Staff to have utility company plans related to outage restoration readily available. At a minimum, the plans would include mutual assistance procedures, communication plans, and planning for vulnerable customers.

Principal points of disagreement

Utility company Workgroup participants submitted multiple comments and shared their concerns during the Workgroup meetings about confidentiality and potential Staff disclosure of the filed ERPs through Freedom of Information Act (FOIA) requests. Workgroup participants, via comments, stated the ERPs should not be made public and recommended they be provided verbally or through other confidential channels. Staff is of the opinion that disclosure of ERPs would be exempt under subsection (y) of the FOIA.

Status

Complete. Staff will not pursue a requirement for the utility companies to submit ERPs at this time. Staff is steadfast in the initial opinion that the ERPs would be exempt from disclosure under subsection (y) of the FOIA, but understands the utility company concerns given the qualifying language in the FOIA law. MCL 15.243(1)(y) exempts emergency response plans from disclosure, however the qualifier says "(1) unless disclosure would not impair a public body's ability to protect the security or safety of persons or property or (2) unless the public interest in disclosure outweighs the public interest in nondisclosure in the particular interest." This language suggests there is not absolute protection from disclosure. However, Staff is confident that Michigan's utility companies will provide the appropriate details and the desired content of their ERPs to Staff for review upon request.

4. Meter Testing

The Commission order in Docket U-20630 asks the workgroups to "consider current and probable future technological advances in electric distribution systems and electric service" and to "recommend changes to the standards in keeping with those advances." Staff contends the current metering inspection and testing rules do not effectively support current meters and equipment in utility distribution systems.

Staff proposal

Update Parts 3 and 6 of the ruleset to reflect modern solid state meters and technologies while considering the fact that electro-mechanical meters are nearing obsolescence but can still be found in utility company distribution systems. Staff proposes to identify electro-mechanical meter requirements that are separate and distinct from solid state meter requirements, where appropriate, to allow for the quick elimination of the electro-mechanical requirements once all such meters are replaced in Michigan.

Principal points of disagreement

None.

Status

Complete. The Metering Subgroup has actively worked to update Parts 3 and 6 since the beginning of 2020. The changes are reflected in Parts 3 and 6 of the Appendix A redline and include the following proposed amendments, among other changes:

- ***Elimination of obsolete equipment*** - eliminates certain obsolete requirements in the current ruleset (e.g. standalone demand meters) and separates rules pertaining to soon-to-be obsolete electro-mechanical meters to help facilitate the elimination of these requirements in future rule revisions. Rules and subrules including the term "ELECTRO-MECHANICAL" in front of the requirement is used as a way to flag specific requirements that will eventually be obsolete while Rule 460.3613a was developed to separate solid state meter testing requirements from electro-mechanical meter testing requirements.

- ***Use of a data interfacing standard*** – incorporates American National Standards Institute (ANSI) C12.22-2012 (American National Standard Protocol Specification for Interfacing to Data Connection Networks) in its entirety to describe the process of transporting data over a variety of networks, with the intention of advancing interoperability among communications modules and meters.

- ***Use of more accurate solid state meters*** - changes provide a more restrictive solid state meter accuracy requirement (0.8% for light and full power factor loads and 1.6% for inductive power factor loads compared to the existing 1.0% and 2.0% respectively) and the ability to shift from normal inspection (the only type of inspection allowed in the current rules) to a tightened and reduced inspection based on the results of the inspections for a specific meter manufacturer type as outlined in ANSI/ASQ Z1.9.

- ***Amended meter reporting to the Commission*** – eliminates reporting of meter tests that have passed testing and requires reporting of meters that have failed. Given the overall trend of nearly all modern meters passing tests, Staff is interested in tests which were rejected the prior year. Additionally, following benchmarking with other states, Staff recommends more of a "records and retention" approach to the ruleset by moving certain requirements, notably calculations performed and passing tests, from the reporting section of the rule (Rule 460.3617) to the records section of the ruleset (Rule 460.3615). In developing proposed meter testing records and reporting requirements, Staff prioritized the ability to request meter test results for complaints, the ability to investigate utility company meter testing facilities, and the ability to stay informed of rejected meter tests.

5. Vegetation Management

The current vegetation management rules do not require customer notifications, nor is there a quality assurance measure in place to ensure that circuits have been cleared to the utility company's prevailing specifications. Staff evaluated options to see if the current rules could be updated to ensure effective vegetation management practices that provide sustained safety and reliability.

Staff proposal

Incorporate pre-trim customer notification and post-trim requirements into the vegetation management rule along with a requirement to provide safety and reliability through the implementation of a line clearance program. Staff also proposes quarterly reporting for vegetation management spending, including any deviations from Commission-approved spending levels. As evidenced in Table 2, the electric distribution plans filed by the three largest investor-owned utilities (IOU) reflect increased vegetation management O&M expenditures in the near-term to improve reliability in the state. Along with increased tree trimming activity comes the need for cooperative and electric utilities to continue to communicate such activity to residents and local government officials in the targeted areas for transparency through pre-trim notifications, which are already performed by most companies for at least a portion of the customers impacted.

Table 2: Electric Distribution Plan Projected Vegetation Management O&M Costs ($ Millions)

IOU	2019	2020	2021	2022
DTE	86	88	91	93
Consumers	43	46	50	53
I&M	9.2	13.2	13.2	13.2

Data from Docket U-20147 electric distribution plan filings.

Principal points of disagreement

Utility companies expressed concerns that pre-trim notifications would be difficult and often impractical to achieve for all customers, specifically landowners in a particular area. Concerns with the notification timeframes were also prevalent. Utility companies also expressed concerns that post-trim inspections would be expensive and that a statistically relevant sample technique should be used. Overall, utilities disagreed with adding more prescriptive vegetation management requirements and, although understanding Staff's desire to stay informed through reporting, generally disagreed with adding new reporting requirements due to resource constraints and questionable usefulness. However, if notification requirements are added, a proposal was made to include prescriptive requirements separating high-voltage distribution (HVD) and low-voltage distribution (LVD) requirements.

Status

Complete. The proposed redline in Appendix A includes line clearing reporting requirements in Rule 460.3203(i) and added line clearance program requirements in Rule 460.3505. A quarterly line clearing report with qualifying language has been added to Rule 460.3203(i) and requires reporting from electric utilities with greater than 100,000 customers and excludes cooperative electric utilities. The proposed requirements for a line clearing program in Rule 460.3505 include 1) the addition of pre-trim notifications prior to tree trimming including procedures for customers and local government officials in areas where maintenance tree trimming is planned,

2) a post-trim inspection using a "statistically relevant representative" sample, and 3) the requirements to implement a line clearance program to ensure safety and reliability. The pre-trim notifications and post-trim audits are necessary to ensure transparency and communication with customers and work quality as utilities perform line clearing maintenance. The intent of including customer and property owner notifications under Rule 460.3505(b) is to add requirements to ensure residents and customers near the targeted tree trim areas are informed of the work taking place far enough in advance while also requiring communication with local government officials to provide an avenue to inform property owners in the area who may not have an address. The added "safety and reliability" language reflects the desire for overall improved distribution reliability in the state as trees are the leading cause of outages today. Benchmarking research performed as part of the Workgroup process suggests that Michigan has broad (i.e. non-prescriptive) vegetation management rules compared to other states, so Staff asked LBNL's Joseph Eto to provide his expertise on the topic of vegetation management during the February 12, 2020 Workgroup meeting. Mr. Eto's presentation responded to Staff's request by presenting three considerations to keep in mind when evaluating vegetation management practices:

1. Do existing standards provide adequate incentives for vegetation management to improve reliability?
2. If not, what are the obstacles to improvements in vegetation management and are prescriptive practices likely to overcome them?
3. What prescriptive standards may be warranted?

Staff opines that the broad language currently in the Technical Standards, which recognizes Part 2, Section 21 of the NESC[14] for line clearing, allows for flexibility by requiring utility companies to apply the appropriate vegetation management specifications and trim frequencies to fit their system needs. This NESC guidance is further refined by Commission orders when necessary. The proposed addition provides the same level of flexibility by holding the utility companies accountable for reliability and safety in implementing the line clearing program. Adding reporting requirements to the rules will allow for the Commission and Staff to effectively track the line clearing spending and dollars per mile (or unit) for each utility with greater than 100,000 customers.

[14] The NESC vegetation management language under 218 states, "[v]egetation management should be performed around supply and communication lines as experience has shown to be necessary. Vegetation that may damage ungrounded supply conductors should be pruned or removed."

6. Voltage Information

The Commission order in Docket U-20630 asks the workgroups to evaluate "potential future rule changes that are flexible and responsive to changing technology and that ensure safe, reliable electric service." Modern meters allow for the ability to capture secondary voltage measurements at the meter, among other information not captured through electro-mechanical meters, which is only slightly accounted for in the current voltage measurement rules, including Rules 460.3703-3704.

Staff proposal

Staff proposes an additional reporting rule to permit the Commission to better understand how each utility company uses the information made available through meter infrastructure investments. Additionally, Staff recommends modifying Rule 460.3703(1) to require voltage measurements at "service points" where permissible for the utility companies.

Principal points of disagreement

Generally, utilities do not support the additional reporting in Rule 460.3203(j) because not all utilities have adopted solid state meters or are in the early stages of adopting solid state meters. Duplicating information submitted in the Smart Grid Annual Report and Distribution Plans was also a concern expressed by utilities.

Status

Complete. Advanced solid state meters in the system today are capable of gathering voltage and other information that is not available with the use of electro-mechanical meters. Staff learned through Workgroup efforts that utilities continue to explore the full capabilities of the meters and how to best use the additional information obtained through the meter infrastructure. Some companies are receiving, for each meter, interval voltage information, minimum and maximum voltages in certain applications, and average voltage over a period of time. Rule 460.3703 permits the utility companies to use meters to measure voltage variations and use the voltage information to a certain extent. Rule 460.3703(2) states in part:

> For installations in which the meter measures voltage variations, measurements using recording voltmeters are not necessary unless records of the measurements through the meter are not available.

Although voltage information is among the most commonly used information sources now available through modern meter infrastructure, it is not the only information the utilities could utilize through their meter investments. Utilities are continuously evaluating the capabilities of modern metering, and Staff is interested in staying informed of what information is collected by utilities and understanding how the additional information can be leveraged to improve utility company operations and customer experience. As a result, Staff recommends annual solid state meter reporting as reflected in Rule 460.3203(j) of Appendix A. The reporting will provide transparency on how utilities are collecting and utilizing the additional data and can assist the

Commission in future recommendations. Staff acknowledges that utilities may report similar information in future filings including, but not limited to, the Annual Smart Grid Report and the Distribution Plan. Staff recommends language be incorporated in the rule to avoid duplication of information provided to the Commission. As advanced meter infrastructure installations reach maturity, utilities must leverage the full range of benefits of AMI to improve operations beyond remote shut-offs in order to further benefit customers.

7. Rule 411

Early in the process, ABATE expressed concerns with Rule 411 (Rule 460.3411). Rule 411 is intended to govern situations involving the extension of electric service to customers in areas served by two or more utilities. The scope of review was ultimately focused on subrule (9) of Rule 411, which applies to "prospective" industrial customers and allows for choice of service from any nearby utility that is willing to construct the necessary facilities to provide service. Under the current version of the rule, existing customers may only receive service from the utility already providing that service, and a suggestion was made to allow existing industrial customers to be treated like prospective industrial customers under subrule (9).

Staff proposal

Staff initially recommended that Rule 411 remain unchanged. Staff now proposes, in the Final Report, that eligible customers are entitled to a meeting with the incumbent utility and the utility from whom they wish to take service, with all other provisions of Rule 411 remaining unchanged. This proposal can be found in Rule 460.3411(16) of Appendix A.

Principal points of disagreement

A Rule 411 Subgroup was created (discussed in more detail below) to discuss proposed revisions to the rule suggested by ABATE. ABATE's concerns were narrowed to subrule (9) of Rule 411, which allows flexibility for "prospective" industrial customers, but not existing industrial customers, to choose an electric supplier. ABATE provided examples of situations where they believe existing industrial customers should be able to choose among providers, such as when an existing facility is razed and rebuilt, or when an upgrade at an existing facility necessitates additional capacity for electric distribution facilities. Utility companies argued that the intent of Rule 411 is to prevent the inefficient duplication of facilities by multiple utilities, and expressed concerns that allowing an existing customer the same level of choice as a "prospective" industrial customer would contradict the intent of the rule. Further, Rule 411 has existed in its current form for decades, and multiple precedent-setting court orders have been issued which provide clarity on interpretation of the rule. Finally, it was argued that expanding the scope of this rule to allow existing customers to choose between utility service providers may run counter to the intent of the Legislature in enacting Public Act 141 of 2000 (as amended by Public Act 286 of 2008) which limits retail electric choice to 10% of a provider's prior-year weather-adjusted sales.

Status

Complete. Staff recommends retaining the existing language in Rule 411 and relying upon the extensive case law related to this rule to continue to allow for consistent interpretation of the rule. The current interpretation of "prospective" customer in Rule 460.3411(9) is aligned with the intent of Rule 411 – to avoid the unnecessary duplication of facilities. Further, subrule (12) of Rule 411 (Rule 460.3411(12)) allows for a utility to waive its rights to serve a customer if another utility is willing and able to provide the required service.

Subsequent to the release of the Initial Report, Staff and ABATE met with representatives from Consumers, a Consumers customer, and I&M to discuss a specific example of an existing industrial customer trying to negotiate service from a different utility. ABATE requested that industrial customers be allowed to request a meeting with the incumbent and adjacent utility providers for the purpose of discussing the proposed connection. In response to ABATE's request, Staff drafted a new subrule (16), which addresses specific instances where an industrial customer can request a meeting with providers. Staff shared the proposed additions to Rule 460.3411(16) with stakeholders for the first time on November 10, 2020. The utilities opined that Rule 411 should remain unchanged and ABATE opined that the proposal shared during the May 5, 2020, subgroup meeting provides more balance between utility protection and customer rights.

8. Standard Frequency

Rule 460.3701 specifies a frequency for alternate current (AC) systems based upon 60 hertz, in order to permit synchronizing with customers' clocks. The rule is outdated as not all customer clocks are connected to the bulk electric system.

Staff proposal

Update the language by amending the second sentence of the rule which states: "The frequency shall be maintained within limits that will permit the satisfactory operation of customers' clocks which are connected to the system."

Principal points of disagreement

None.

Status

Complete. The proposed redline is provided in Appendix A in Rule 460.3701. A proposal was shared with the Workgroup on March 12, 2020. Comments were also submitted in response to the Initial Report which resulted in small changes to the language.

9. Cybersecurity Standards

Recommendation S-2 of the SEA instructs Staff, in part, to evaluate existing Commission rules for opportunities to enhance the cybersecurity of electric distribution infrastructure. At present, Commission rules require utilities to have a Commission-approved data privacy policy and to report certain cybersecurity information to the Commission. In addition, some electric utilities in

Michigan must follow, and in other instances choose to follow, cybersecurity-related standards or guidelines from entities such as the North American Electric Reliability Corporation or the National Institute of Standards and Technology that touch on varying aspects of their operations. Nonetheless, Staff notes that there is currently no uniform set of broad, foundational cybersecurity practices that all electric utilities under the Commission's purview must follow. Staff argues that cybersecurity is a growing issue that is too important to not ensure baseline cyber protections are in place.

Staff proposal

Michigan utilities employ a broad array of systems, processes, controls, and policies to protect utility and customer information and assets. These disparate approaches reflect rapidly evolving threat, technological, and policy environments in the utility cybersecurity space. As such, Staff argues that any cybersecurity requirements put forward in the Technical Standards should provide sufficient flexibility to continue to make use of existing information technology and cybersecurity investments and policies while ensuring Michigan's electric utilities continue to grow and maintain a comprehensive, risk-informed cybersecurity program.

In light of the above, Staff proposes that a new rule requiring utilities to maintain a cybersecurity program, based on foundational best practices, be added to the Technical Standards. The proposed rule requires utilities to address information assurance and asset protection, incident response, electronic access control, software vulnerability mitigation, risks from suppliers and vendors, and other cybersecurity issues. The proposed rule would also require periodic cybersecurity exercises, training, and assessments to promote overall cybersecurity knowledge and preparedness. Lastly, it would require utilities to provide a document annually attesting to their compliance with the rule and that the attestation be signed by an official of the utility who is authorized to manage the operations of the cybersecurity program.

Principal points of disagreement

None.

Status

Complete. The proposed redline is provided in Appendix A in Rule 460.3506.

10. Security Reporting

In its November 22, 2016, order in Docket U-18203, the Commission directed Staff to "include rules concerning cybersecurity reporting in amendments to the Technical Standards for Gas

Service and Technical Standards for Electric Service."[15] With respect to the Technical Standards for Electric Service, this directive resulted in Rule 205, which went into effect on January 9, 2019. A similar rule, Rule 24, was approved by the Commission in Docket U-20608 for the Technical Standards for Gas Service[16] and went into effect on September 3, 2020.

During a comment period for the Technical Standards for Gas Service, the Retail Energy Supply Association noted that the terminology used in Rule 24, as originally drafted, could be interpreted as applying to certain non-utility gas providers, which, they argued, among other things, would go beyond the defined scope of the standards. The Commission agreed, finding that references to "gas provider" in Rule 24 should be replaced by the defined term "utility." Staff contends that an analogous issue arises in Rule 205 of the Technical Standards for Electric Service, which uses the term "electric provider" that should therefore be replaced by the term "utility."

In response to this proposed change, DTE recommended the definition of "utility" in the Technical Standards be amended to reflect the intended jurisdictional scope of the ruleset. It is Staff's long-held position that the Technical Standards apply to both Michigan's investor-owned and cooperative electric utilities, but do not apply to entities such as alternative electric suppliers or municipal electric utilities. Upon further review, Staff believes that the existing definition of "utility" in Technical Standards may not appropriately capture this distinction. Accordingly, Staff is proposing to modify its current definition of "utility" and to add a definition for "cooperative electric utility" to help clarify the intended scope of the Technical Standards.

Additionally, Rule 205 and Rule 24 require electric and gas utilities, respectively, to notify the Commission and the Michigan fusion center in advance if they experience an incident requiring public notification under Michigan's Identity Theft Protection Act. The reference to this requirement in Rule 24 was modified by Staff during the rulemaking process for the Technical Standards for Gas Service, where the rule now ties to the statutorily defined term of "security breach" rather than to the compromise of "personal information." Staff contends that this modification clarifies the requirement without altering its substance or intent. The Commission approved the modification to Rule 24, and Staff argues a similar modification should therefore be made to Rule 205. Staff acknowledges that this requirement may lead to the reporting of some relatively minor incidents that are not the primary focus of this notification requirement. Rule 205(2) endeavors to balance the Commission's need to be informed of noteworthy security

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[15] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UVVQAA4
[16] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009SsaYAAS

incidents with the corresponding impact to utilities' reporting burdens and procedures. While Staff does not intend to modify the substance of these requirements at this time, it is committed to working with stakeholders going forward should these requirements fail to produce an appropriate balance.

Staff proposal

Staff proposes to modify Rule 205 and Rule 102 of the Technical Standards for Electric Service to reflect the changes discussed above. Staff argues that these changes improve the clarity of Rule 205 and provides greater consistency across the gas and electric technical standards rulesets.

Principal points of disagreement

None.

Status

Complete. The proposed redline is provided in Appendix A in Rule 460.3205.

Technical Standards Subgroups

To facilitate focused discussions with subject-matter experts (SMEs), Staff assembled topic-specific subgroups and conducted subgroup meetings in addition to the larger Workgroup meetings. Three subgroups were established to update the Technical Standards ruleset: Metering Subgroup, Rule 411 Subgroup, and Cyber Subgroup.

Metering Subgroup

The subgroup members are utility company metering SMEs from IOUs and associations representing IOUs and cooperative utilities. The subgroup meetings began in January of 2020 and have occurred monthly on the following dates:

- January 24, 2020 - DTE's Ann Arbor offices
- February 26, 2020 – Teleconference
- March 30, 2020 – Teleconference
- April 27, 2020 – Teleconference
- May 20, 2020 – Teleconference
- June 18, 2020 – Teleconference
- July 9, 2020 – Teleconference
- August 26, 2020 - Teleconference

Initial efforts focused on determining which current rules are obsolete and which rules must be revised to reflect the modern meters in the system. An inventory of meters was obtained to gauge how quickly electro-mechanical meters were being phased out. This work also involved identifying specific requirements pertaining to electro-mechanical meters only and labeling these areas in a way that permits the MPSC to seamlessly eliminate specific requirements once electro-mechanical meters are no longer in the utility systems. The subgroup made these locations within the rules clear by using the term "electro-mechanical" as an identifier and even divided entire rulesets to clearly separate soon-to-be obsolete requirements so they can be easily identified in future updates. Below is a table showing the current meter characteristics in IOU and cooperative utility systems today. In the past, electro-mechanical meters were coupled with separate, standalone demand meter installations while modern electric meters are essentially demand meters and electricity usage meters combined into one. It is important to understand this delineation in the context of Table 3 below as there are certain requirements in the Technical Standards today that apply to standalone demand meters only. The proposed redline changes attached in Appendix A are responsive to the results in the table and are intended to eliminate obsolete requirements in the current ruleset. There were also discussions regarding whether to incorporate ANSI C12.22-2012[17] into the ruleset and how that should be done. The subgroup decided to incorporate ANSI C12.22-2012 into the rules in its entirety as the standard is responsive to the modern technologies in the systems today and serves to describe the process of transporting C12.19 table data over a variety of networks.

Table 3: IOU and Cooperative Utility Meter Characteristics, July 2020

	IOUs	Coops
Electro-mechanical Meters (Y/N)	Y	Y
Solid state Meters (Y/N)	Y	Y
Associated Devices (Y/N)	Y	Y
Standalone Demand Meters (Y/N)	N	N
Charts and Magnetic Tapes (Y/N)	N	N

Next, the subgroup eliminated language in the rules that may already be implied through a Standard incorporated by reference, clarified language to make the rules easier to read and interpret, and updated the meter testing requirements in response to the increased accuracy of modern meters. Public Sector Consultants' benchmarking study was used in reviewing the accuracy thresholds used by other states. Given that meter manufacturers generally supply meters with a 0.5% accuracy, the subgroup agreed that requiring an accuracy of 0.8% accuracy is appropriate for the light load and full load power factor loads and 1.6% (double the 0.8%) is appropriate for inductive load.

[17] ANSI C12.22-2012 is a standard describing the process of transporting ANSI C12.19 table data over networked connections with the intent of advancing interoperability among communications modules and meters and is fully extensible to support additional security mechanisms the industry may require in the future.

The focus later evolved into how to incorporate the ability to move from normal inspection only to a reduced or tightened inspection for solid state meters given the recent inspection results of a specific meter manufacturer and type. This flexibility is outlined in ANSI/ASQ Z1.9 and is responsive to the overall improved accuracy and test results of solid state meters. ANSI/ASQ Z1.9 relies on mathematics and statistics in determining what inspection category a certain meter manufacturer type should be in, given inspection findings which could change over time. The meter inspection results issued to the MPSC each year also demonstrate that solid state meters in the system have extremely low failure rates, strengthening the argument that added flexibility should be granted for the inspection of solid state meters. The language providing added flexibility for inspection of solid state meters is reflected in Rule 460.3613 of Appendix A.

Since the Initial Report submission, the group refined the switching procedure language in Rule 613 and amended the annual reporting requirements to the Commission as outlined in Rule 617. After benchmarking meter testing and inspection reporting and retention requirements in other states, Staff determined a "records and retention" approach should be pursued which preserves the Commission's ability to request records, when deemed necessary, for complaint or investigation purposes. Staff also recommends focusing the annual reporting requirements on the meter tests and inspections that have been rejected or failed, rather than requiring reporting of all meter testing results.

Rule 411 Subgroup

The Rule 411 subgroup was established to explore the limitation for existing industrial customers to choose their electric service provider for expanded load. The existing rule allows choice of electric provider for "prospective" industrial customers only (Rule 460.3411(9)). The subgroup included ABATE, utility staff and representative associations.

The first subgroup meeting took place March 5, 2020 and featured a proposed rule revision developed by ABATE. The proposed change allows existing customers to have a choice of electric service from any nearby utility. As proposed, the draft Rule 460.411(9) stated:

> *Regardless of any other provisions in these rules, an ~~prospective~~ industrial customer, as defined under the industrial classification manual, division D, manufacturing, for 3-phase service that has or will have a connected load of more than 500 kilowatts shall have its choice of service from any nearby utility. ~~that is willing to construct the necessary facilities~~. The facilities that are constructed to serve an industrial customer that would otherwise have been served by another utility shall not qualify as a measuring point in determining which utility will serve new customers in the future.*

After discussing this proposal, the meeting concluded with ABATE agreeing to provide an updated proposed rule revision.

The second subgroup meeting was held virtually and took place on May 5, 2020. ABATE's second proposal included definitions for "industrial buildings and facilities" and "prospective industrial customer," along with further changes to Rule 460.3411(9). Examples were also provided to the subgroup to provide context for ABATE's Rule 411 proposed revisions. ABATE's proposal for Rule 460.3411(9) was as follows:

> *~~Regardless of~~ Notwithstanding any other provisions in these rules, a prospective industrial customer, ~~as defined under the industrial classification manual, division D, manufacturing, for 3-phase service that will have a connected load of more than 500 kilowatts~~ shall have its choice of service from any ~~nearby~~ utility that has obtained any and all necessary franchise rights from the applicable local governments and, if mandated by law, a certificate of necessity from the Commission under Act No. 69 of the Public Acts of 1929, as amended, being §460.501 et seq. of the Michigan Compiled Laws. ~~is willing to construct the necessary facilities. The facilities that are constructed to serve an industrial customer that would otherwise have been served by another utility shall not qualify as a measuring point in determining which utility will serve new customers in the future.~~*

The proposal was widely discussed; however, after careful consideration, Staff recommended in the Initial Report that Rule 411 should remain unchanged.

A third and final subgroup meeting was held virtually and took place on October 28, 2020. Meeting attendees included Staff, ABATE, Consumers, a Consumers customer, and I&M. During the meeting, the stakeholders discussed, among other things, a proposal by ABATE to allow an industrial customer meeting certain requirements to request a meeting with the incumbent utility and a nearby utility for purposes of a non-binding discussion on a potential waiver. Staff found ABATE's proposal to be reasonable, and subrule (16) was added to Rule 411 in the redline.

Cybersecurity Subgroup

Due to the complexity in creating an entirely new rule – particularly in a subject area that is rapidly evolving – Staff created an initial draft of the proposed Cybersecurity Program rule and invited SMEs from all of Michigan's investor-owned and cooperative electric utilities, as well as representatives from MEGA and MECA, to help improve upon Staff's initial proposal.

The subgroup held its initial meeting via teleconference on April 8, 2020, where Staff provided an overview of its initial proposal and solicited feedback from the subgroup members. Subsequent meetings were held via teleconference on May 13, 2020 and July 29, 2020, where members helped to refine the proposed rule. To Staff's knowledge, no member of the subgroup holds a firm objection to the substance of the proposed rule, though the subgroup continues to seek opportunities to improve the proposed rule's precision and clarity.

Staff Recommendations

For the reasons discussed in this Final Report, Staff recommends:

1. The Commission consider the suitability of the proposed redlines in Appendix A, which reflect the Workgroup and subgroups' work to date, for future inclusion in the Technical Standards.
2. The Commission consider opening the Billing Rules when the Technical Standards are opened for revision to facilitate the changes identified as a result of the Workgroup. This will allow the Technical Standards and Billing Rules to progress through the rulemaking process at the same time.

Conclusion

Staff appreciates the Workgroup members' efforts and contributions to the substance of this report. Their participation and input through presentations and comments were essential in identifying and resolving issues. Staff also thanks the guidance and technical expertise provided by Lawrence Berkeley National Laboratory throughout this entire process.

The Workgroup has been responsive to the Commission's orders in Dockets U-20464 and U-20630 and its efforts have resulted in many proposed changes to the Technical Standards, most of which have a consensus.

Appendix A

DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

TECHNICAL STANDARDS FOR ELECTRIC SERVICE

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 2 of 1909 PA 300, MCL 462.2, section 5 of 1919 PA 419, MCL 460.55, sections 4 and 6 of 1939 PA 3, MCL 460.4 and 460.6, and sections 3, 9, and 231 of the executive organization act of 1965, 1965 PA 380, MCL 16.103, 16.109, 16.331, and Executive Reorganization Order Nos. 1996-2, 2003-1, 2008-4, and 2011-4, MCL 445.2001, 445.2011, 445.2025, and 445.2030)

PART 1. GENERAL PROVISIONS

R 460.3101 Applicability; purpose; modification; adoption of rules and regulations by electric utility or electric cooperative.

Rule 101. (1) These rules apply to electric utilities as defined as defined by MCL 460.562(e) and cooperative electric utilities as defined by MCL 460.32(c). ~~utility service that is provided by electric utilities that are subject to the jurisdiction of the public service commission.~~

(2) These rules are intended to promote safe and adequate service to the public and to provide standards for uniform and reasonable practices by electric utilities and electric cooperatives.

(3) These rules do not relieve an electric utility or electric cooperative from any of its duties under the laws of the state of Michigan. (See R 460.1601(3).)

(4) Each electric utility or electric cooperative may adopt reasonable rules and regulations governing its relations with customers which it finds necessary and which are not inconsistent with these rules for electric service. Adopted rules and regulations must be filed with, and approved by, the commission.

(5) An electric utility or electric cooperative may petition the commission for a permanent or temporary waiver or exception from these rules for good cause shown provided that the waiver or exception is consistent with the purpose of these rules.

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3102 Definitions.

Rule 102. As used in these rules:

(a) “Approved by the commission” means that a commission order has been issued.

(b) “Commission” means the Michigan public service commission.

(c)“Cooperative" or "electric cooperative" means that term as defined in section 2 of 2008 PA 167, MCL 460.32(c).

(d) “Customer” means an account holder who purchases electric service from an electric utility or electric cooperative. An individual who is a customer must be at least 18 years of age or an emancipated minor.

(e) "Electric utility" or “utility” means that term as defined in section 2(e) of 1995 PA 30, MCL 460.562(e).

(f) “Electric plant” means all real estate, fixtures, or property that is owned, controlled, operated, or managed in connection with, or to facilitate the production, transmission, and delivery of, electric energy.

(g) “Electricity meter” means a device that measures and registers the integral of an electrical quantity with respect to time.

(h) “Electro-mechanical meter” means a meter in which currents in fixed coils react with the currents induced in the conducting moving element, generally a disk or disks, which causes their movement proportional to the energy to be measured. This meter may also be called an induction watthour meter.

(i) “File” means to deliver to the commission’s executive secretary.

(j) “Major interruption” means either of the following:

(i) For each electric utility or electric cooperative with greater than one million customers, any weather condition that results in sustained service interruptions impacting 50,000 or more customers or an electrical system component failure that occurs under normal conditions, as defined in R 460.702, impacting 7,500 or more customers unless otherwise ordered by the Commission.

(ii) For each electric utility or electric cooperative with less than one million customers, any weather condition that results in sustained service interruptions impacting 5% or 2,000 or more customers, whichever is greater, or an electrical system component failure that occurs under normal conditions, as defined in R 460.702, impacting 3,000 or more customers unless otherwise ordered by the Commission.

(k) “Meter” or “watthour meter” means an electricity meter that measures and registers the integral with respect to time of the active power of the circuit in which it is connected. The unit by which this integral is measured is usually the kilowatt-hour.

(l) “Meter error” means a failure to accurately measure and record all of the electrical quantities used that are required by the applicable rate or rates.

(m) “Meter shop” means a shop where meters are inspected, repaired, and tested. A meter shop may be at a fixed location or may be mobile.

(n) “Planned interruption” means the loss of electric power to one or more customers that results from a planned outage.

(o) “Premises” means an undivided piece of land that is not separated by public roads, streets, or alleys.

(p) “Regional transmission organization” means a voluntary organization of electric transmission owners, transmission users, and other entities approved by the Federal Energy Regulatory Commission to efficiently coordinate electric transmission planning, operation, and use on a regional and interregional basis.

(q) “Serious injury” means any injury or illness to an employee, including contract employees, or non-employee that results in inpatient hospitalization.

(r) "Service point" means the point of connection between the facilities of the serving electric utility or electric cooperative and the premises wiring.

(s) "Solid state meter" means a meter in which current and voltage act on electronic (solid state) elements to produce an output proportional to the energy to be measured.

(t) "Submit" means to deliver to the commission's designated representative.

(u) "Sustained interruption" means any interruption not classified as a part of a momentary event – that is, any interruption that lasts more than five minutes. The duration of a customer's interruption shall be measured from the time that the electric utility or electric cooperative is notified or otherwise becomes aware of the full or partial loss of service to one or more customers for longer than five minutes.

~~(v) "Utility" means a firm, corporation, cooperative, association, or other legal entity that is subject to the jurisdiction of the commission and that distributes, sells, or provides electric service.~~

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3103 Rescission.

Rule 103. R 460.501 to R 460.505 of the Michigan Administrative Code, appearing on pages 4695 to 4709 of the 1979 Michigan Administrative Code, are rescinded.

History: 1983 AACS.

PART 2. RECORDS, ~~AND~~ REPORTS, AND OTHER INFORMATION

R 460.3201 Records; location; examination.

Rule 201. Upon a request by the commission or its designated representative, records which are required by these rules or which are necessary for the administration of these rules shall be available within the state of Michigan for examination by the commission or its designated representative.

History: 1983 AACS; 1996 AACS.

R 460.3202 Records; preservation.

Rule 202. Unless otherwise specified in these rules, or by other order of the commission, all records that are required by these rules shall be preserved for the period of time specified in R 460.2501 et seq. of the Michigan Administrative Code.

History: 1983 AACS.

R 460.3203 Documents and information; required submission.

Rule 203. An electric utility or electric cooperative shall submit all of the following documents and information and shall maintain the documents and information in a current status:

(a) A copy of the electric utility's or electric cooperative's tariff.

(b) A copy of the electric utility's or electric cooperative's rules and standards that are made available to the public covering meter and service installation.

(c) A copy of each type of customer bill form.

(d) A list of the cities, villages, and townships that the electric utility or electric cooperative serves. Upon a request by the commission or its designated representative, the electric utility or electric cooperative shall also provide copies of the associated franchise information.

(e) The name, title, address, and telephone number of the persons to be contacted in connection with the following matters:

(i) General management duties.

(ii) Customer relations (complaints).

(iii) Engineering operations.

(iv) Meter tests and repairs.

(v) Emergencies during non-office hours.

(f) An annual copy of the electric utility's or electric cooperative's construction budget, which shall be updated for all major changes to generating and transmission facilities.

(g) An "Electric Service" monthly report, on forms suitable to the commission, that shows information concerning the electric utility's or electric cooperative's acquisition and disposition of electric energy and other information as required. The reports shall be submitted by ~~investor-owned~~ electric utilities or electric cooperatives within 50 days after the end of the quarter reported. ~~and by rural electric cooperatives within 50 days after the end of the month reported.~~

(h) A map or maps that show the electric utility's or electric cooperative's operating area within this state, including generating stations and transmission lines with their voltage designations. Upon a request by the commission or its designated representative, the electric utility or electric cooperative shall also make available a map or maps that show all of the following:

(i) Distribution lines with the number of phases designated.

(ii) State boundary crossings.

(iii) Service areas.

(i) For an electric utility with greater than 100,000 customers, a line clearing quarterly report, on forms suitable to the commission, that shows information concerning line clearing amounts spent, miles or units cleared, and progress toward achieving the targeted line clearing cycle.

(j) Unless provided through other written reporting to the Commission, a solid state meter annual report, on forms suitable to the commission, that shows all of the following:

(i) Information the meter infrastructure is capable of collecting.

(ii) Information the electric utility or electric cooperative is collecting from the meter infrastructure.

(iii) A description of the electric utility's or electric cooperative's current use of the information collected.

(iv) A description of the electric utility's or electric cooperative's future plans for information collection and use.

History: 1983 AACS; 1996 AACS.

R 460.3204 Customer records; retention period; content.

Rule 204. (1) The electric utility or electric cooperative shall retain, either within the electric utility or electric cooperative or as contracted through a third party with access by the electric utility or electric cooperative, customer records as necessary to comply with R 460.3309. The electric utility or electric cooperative shall retain the records for not less than 3 years.

(2) Records for customers must show, if applicable, all of the following information:

(a) Kilowatt-hour meter reading.

(b) Metered kilowatt-hour consumption.

(c) Kilowatt, kilovolt ampere, and kilovar meter reading.

(d) Kilowatt, kilovolt ampere, and kilovar measured demand.

(e) Kilowatt, kilovolt ampere, and kilovar billing demand.

(f) Total amount of bill.

History: 1983 AACS; 1996 AACS; 2008 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3205 Security reporting.

Rule 205. (1) To inform the commission regarding matters that may affect the security or safety of persons or property, whether public or private, an ~~electric provider~~ electric utility or electric cooperative must do ~~both~~ all of the following:

(a) Provide a written or oral annual report, individually or jointly with other ~~electric providers~~ electric utilities or electric cooperatives, to designated members of the commission staff regarding the ~~electric provider's~~ electric utility's or electric cooperative's cybersecurity program and related risk planning. This report on the threat assessment and preparedness strategy must contain all of the following information:

(i) An overview of the program describing the ~~electric provider's~~ electric utility's or electric cooperative's approach to cybersecurity awareness and protection.

(ii) A description of cybersecurity awareness training efforts for the ~~electric provider's~~ electric utility's or electric cooperative's staff members, specialized cybersecurity training for cybersecurity personnel, and participation by the ~~electric provider's~~ electric utility's or electric cooperative's cybersecurity staff in emergency preparedness exercises in the previous calendar year.

(iii) An organizational diagram of the ~~electric provider's~~ electric utility's or electric cooperative's cybersecurity organization, including positions and contact information for primary and secondary cybersecurity emergency contacts.

(iv) A description of the ~~electric provider's~~ electric utility's or electric cooperative's communications plan regarding unauthorized actions that result in loss of service, financial harm, or breach of sensitive business or customer data, including the ~~electric provider's~~ electric utility's or electric cooperative's plan for notifying the commission and customers.

(v) A redacted summary of any unauthorized actions that resulted in material loss of service, financial harm, or breach of sensitive business or customer data, including the parties that were notified of the unauthorized action and any remedial actions undertaken.

(vi) A description of the risk assessment tools and methods used to evaluate, prioritize, and improve cybersecurity capabilities.

(vii) General information about current emergency response plans regarding cybersecurity incidents, domestic preparedness strategies, threat assessments, and vulnerability assessments.

(b) In addition to the information required under subdivision (a) of this subrule, an investor-owned electric ~~public~~ utility must include in its annual report to the Michigan public service commission an overview of major investments in cybersecurity during the previous calendar year and plans and rationale for major investments in cybersecurity anticipated for the next calendar year.

(2) As soon as reasonably practicable and prior to any public notification, an ~~electric provider~~ electric utility or electric cooperative must orally report the confirmation of a cybersecurity incident to a designated member of the commission staff and to the Michigan fusion center, unless prohibited by law or court order or instructed otherwise by official law enforcement personnel, if any of the following occurred:

(a) A person intentionally interrupted the production, transmission, or distribution of electricity.

(b) A person extorted money or other thing of value from the ~~electric provider~~ electric utility or electric cooperative through a cybersecurity attack.

(c) A person caused a denial of service in excess of 12 hours.

(d) ~~An unauthorized person accessed or acquired data that compromises the security or confidentiality of personal information maintained by the electric provider, as defined by section 3(r) of the identity theft protection act, 2004 PA 452, MCL 445.63(r)~~ A security breach, as defined by section 3(b) of the identity theft protection act, 2004 PA 452, MCL 445.63(b), prior to public and customer notification.

(e) At the ~~electric provider's~~ electric utility's or electric cooperative's discretion, any other cybersecurity incident, attack, or threat which the ~~electric provider~~ electric utility or electric cooperative deems notable, unusual, or significant.

~~(3) For purposes of this rule, "electric provider" means any of the following:~~

~~(a) Any person or entity that is regulated by the commission for the purpose of selling electricity to retail customers in this state.~~

~~(b) A member-regulated cooperative electric utility in this state.~~

~~(4)~~ (3) For purposes of subrule (2) of this rule, "person" means any individual, firm, corporation, educational institution, financial institution, governmental entity, or legal or other entity.

~~(5)~~ (4) For purposes of subrule (2)(c) of this rule, "denial of service" means, for an ~~electric provider~~ electric utility or electric cooperative, a successful attempt to prevent a legitimate user from accessing electronic information made accessible by the ~~electric provider~~ electric utility or electric cooperative or by another party on the behalf of the ~~electric provider~~ electric utility or electric cooperative.

History: 2019 MR 1, Eff. Jan. 9, 2019.

PART 3. METER REQUIREMENTS

R 460.3301 Metered measurement of electricity required; exceptions.

Rule 301. (1) All electricity that is sold by an electric utility or electric cooperative shall be on the basis of meter measurement, except where the consumption can be readily computed or except as provided for in an electric utility's or electric cooperative's filed rates.

(2) Where practicable, the consumption of electricity within the electric utility or electric cooperative or by administrative units associated with the electric utility or electric cooperative shall be metered.

(3) Meters shall be in compliance with part 6 of these rules.

History: 1983 AACS; 1996 AACS.

R 460.3302 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3303 Meter reading data.

Rule 303. The meter reading data must include all of the following information:

(a) A suitable designation identifying the customer.

(b) Identifying number and description of the meter.

(c) Meter readings or, if an electric utility or electric cooperative cannot obtain an actual meter reading, then the electric utility or electric cooperative shall maintain records of the efforts made to obtain such a reading and its reasons for failing to obtain it. ~~a reading was not taken, an indication that a reading was not taken.~~

(d) Any applicable multiplier or constant.

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3304 Meter data management ~~collection~~ system.

Rule 304. A meter data management ~~collection~~ system that takes data from recording meters must indicate all of the following meter information:

(a) The date of the record.

(b) The equipment numbers.

(c) A suitable designation identifying the customer.

(d) The appropriate multipliers.

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3305 Meter multiplier.

Rule 305. If it is necessary to apply a multiplier to the meter registration, then the multiplier shall be displayed on ~~the face of~~ the meter.

History: 1983 AACS; 1996 AACS.

R 460.3306 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3307 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3308 Standards of good practice; adoption by reference.

Rule 308. In the absence of specific rules of the commission, an electric utility or electric cooperative shall apply the provisions of the publications set forth in this rule as standards of accepted good practice. The following standards are available from the American National Standards Institute (ANSI), Customer Service, 25 West 43rd St., 4th floor, New York, New York, 10036, USA, telephone number: 1-212-642-4900 or via the internet at website: http://webstore.ansi.org at the cost listed below as of the time of adoption of these rules, plus a handling charge (for paper copies):

(a) American National Standards Institute standards for electricity meters ANSI C12.1-2014, cost $279.00, ~~and~~ C12.20-2015, cost $115.56 ~~107.00~~, and C12.22-2012, cost $250.95.

(b) American National Standards Institute/American Society for Quality Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming (ANSI/ASQ Z1.9-2003(R2018~~3~~)). Cost $179.00.

(c) American National Standards Institute IEEE Standard Requirements for Instrument Transformers (ANSI C57.13-2016). Cost $119.00.

(d) American National Standards Institute IEEE Standard for High Accuracy Instrument Transformers, IEEE Std. C57.13.6-2005. Cost $50~~7~~.00.

History: 1996 AACS; 2008 AACS; 2019 MR 1, Eff. Jan. 9, 2019; 2019 MR 13, Eff. July 16, 2019.

~~**R 460.3309 Metering inaccuracies; billing adjustments.**~~

~~Rule 309. (1) An adjustment of bills for service for the period of inaccuracy must be made for over registration and may be made for under registration under any of the following conditions:~~

~~(a) ELECTRO-MECHANICAL: A mechanical meter creeps.~~

~~(b) A metering installation is found upon any test to have an average inaccuracy of more than 2.0%.~~

~~(c) A demand metering installation is found upon any test to have an average inaccuracy of more than 1.0% in addition to the inaccuracies allowed under R 460.3609.~~

~~(d) A meter registration has been found to be inaccurate due to apparent tampering by a~~

~~person or persons known or unknown.~~

~~(2) The amount of the adjustment of the bills for service must be calculated on the basis that the metering equipment is 100% accurate with respect to the testing equipment used to make the test. The average accuracy of watt-hour meters must be calculated in accordance with R 460.3616.~~

~~(3) If the date when the inaccuracy in registration began can be determined, then that date must be the starting point for determining the amount of the adjustment and is subject to R 460.115.~~

~~(4) If the date when the inaccuracy in registration cannot be determined, then it is assumed that the inaccuracy existed for the period of time immediately preceding discovery of the inaccuracy that is equal to 1/2 of the time since the meter was installed on the present premises, 1/2 of the time since the last test, or 6 years, whichever is the shortest period of time, except as otherwise provided in subrule (5). of this rule and subject to subrule (12) of this rule.~~

~~(5) ELECTRO-MECHANICAL: The inaccuracy in registration due to creep must be calculated by timing the rate of the creeping under R 460.3607 and by assuming that the creeping affected the registration of the meter for the period of time immediately preceding discovery of the inaccuracy that is equal to 1/4 of the time since the meter was installed on the present premises, 1/4 of the time since the last test, or 6 years, whichever is the shortest period of time, subject to subrule (12) of this rule.~~

~~(6) If the average inaccuracy cannot be determined by test because part, or all, of the metering equipment is inoperative, then the utility may use the registration of check metering installations, if any, or estimate the quantity of energy consumed based on available data. The utility shall advise the customer of the metering equipment failure and of the basis for the estimate of the quantity billed. The same periods of inaccuracy must be used as explained in this rule.~~

~~(7) Recalculation of bills must be on the basis of the recalculated monthly consumption.~~

~~(8) Refunds must be made to the 2 most recent customers who received service through the meter found to be inaccurate. If a former customer of the utility, a notice of the amount of the refund must be mailed to such customer at the last known address. The utility shall, upon demand made by the customer within 3 months of mailing of the notice, forward the refund to the customer.~~

~~(9) If the external meter display is not operating so that the customer can determine the energy used, but the meter is recording energy correctly, then no adjustment is required. The utility shall repair or replace the meter promptly upon discovery of the failure.~~

~~History: 1983 AACS; 1996 AACS; 2008 AACS; 2019 MR 1, Eff. Jan. 9, 2019~~.

PART 4. CUSTOMER RELATIONS

R 460.3401 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3402 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3403 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3404 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3405 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3406 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3407 Rescinded.

History: 1983 AACS; 1996 AACS; 2008 AACS.

R 460.3408 Temporary service; cost of installing and removing equipment owned by electric utility or electric cooperative.

Rule 408. If the electric utility or electric cooperative renders temporary service to a customer, it shall require that the customer bear the cost of installing and removing the electric utility or electric cooperative-owned equipment in excess of any salvage realized.

History: 1983 AACS; 1996 AACS.

R 460.3409 Protection of electric utility or electric cooperative-owned equipment on customer's premises.

Rule 409. (1) The customer shall use reasonable diligence to protect electric utility or electric cooperative-owned equipment on the customer's premises and to prevent tampering or interference with the equipment. The electric utility or electric cooperative may shut off service in accordance with applicable rules of the commission if the metering or wiring on the customer's premises is unsafe, or has been tampered with or altered in any manner that allows unmetered or improperly metered energy to be used.

(2) If an electric utility or electric cooperative shuts off service for unauthorized use of service, then both of the following provisions apply:

(a) The electric utility or electric cooperative may bill the customer for the unmetered energy used and any damages that have been caused to electric utility or electric cooperative-owned equipment.

(b) The electric utility or electric cooperative is not required to restore service until the customer does all of the following:

(i) Makes reasonable arrangements for payment of the charges in subdivision (a) of this subrule.

(ii) Agrees to pay the approved reconnection charges.

(iii) Agrees to make provisions and pay charges for relocating electric utility or electric cooperative-owned equipment or making other reasonable changes that may be requested by the electric utility or electric cooperative to provide better protection for its equipment.

(iv) Provides the electric utility or electric cooperative with reasonable assurance of the customer's compliance with the electric utility's or electric cooperative's approved standard rules and regulations.

(3) Failure to comply with the terms of an agreement to restore service after service has been shut off pursuant to subrule (1) of this rule is cause to shut off service in accordance with the rules of the electric utility or electric cooperative and the commission.

(4) If service is shut off pursuant to subrule (3) of this rule and the electric utility or electric cooperative must incur extraordinary expenses to prevent the unauthorized restoration of service, the electric utility or electric cooperative may bill the customer for the expenses, in addition to all other charges that may apply under this rule, and may require that the expenses and other charges be paid before restoring service. A reasonable effort must be made to notify the customer at the time of shutoff that additional charges may apply if an attempt is made to restore service that has been shut off.

(5) The customer of record who benefits from the unauthorized use is responsible for payment to the electric utility or electric cooperative for the energy consumed.

(6) The electric utility or electric cooperative may bill the customer for the reasonable actual cost of the tampering investigation.

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3410 Extension of facilities plan.

Rule 410. Each electric utility or electric cooperative shall develop a plan, approved by the commission, for the extensions of facilities where the investment is in excess of that included in the regular rates for service and for which the customer is required to pay all or part of the cost.

History: 1983 AACS; 1996 AACS.

R 460.3411 Extension of electric service in areas served by 2 or more electric utilities or electric cooperatives.

Rule 411. (1) As used in this rule:

(a) "Customer" means the buildings and facilities served rather than the individual, association, partnership, or corporation served.

(b) "Distances" means measurements which are determined by direct measurement from the closest point of an electric utility's or electric cooperative's existing distribution facilities to the customer's meter location and which are not determined by the circuit feet involved in any extension.

(c) "Distribution facilities" means single-phase, V-phase, and 3-phase facilities and does not include service drops.

(2) Existing customers shall not transfer from one electric utility or electric cooperative to another.

(3) Prospective customers for single-phase service that are located within 300 feet of the distribution facilities of 2 or more electric utilities or electric cooperatives shall have the service of their choice.

(4) Prospective customers for single-phase service that are located more than 300 feet, but within 2,640 feet, from the distribution facilities of 1 or more electric utilities or electric cooperatives shall be served by the closest electric utility or electric cooperative.

(5) Prospective customers for single-phase service that are located more than 2,640 feet from the distribution facilities of any electric utility or electric cooperative shall have the service of their choice, subject to the provisions of subrule (10) of this rule.

(6) Prospective customers for 3-phase service that are located within 300 feet of the 3-phase distribution facilities of 2 or more electric utilities or electric cooperatives shall have the service of their choice.

(7) Prospective customers for 3-phase service that are located more than 300 feet, but within 2,640 feet, from the 3-phase distribution facilities of 1 or more electric utilities or electric cooperatives shall be served by the closest electric utility or electric cooperative.

(8) Prospective customers for 3-phase service that are located more than 2,640 feet from the 3-phase distribution facilities of any electric utility or electric cooperative shall have the service of their choice, subject to the provisions of subrule (10) of this rule.

(9) Regardless of any other provisions in these rules, a prospective industrial customer, as defined under the industrial classification manual, division D, manufacturing, for 3-phase service that will have a connected load of more than 500 kilowatts shall have its choice of service from any nearby electric utility or electric cooperative that is willing to construct the necessary facilities. The facilities that are constructed to serve an industrial customer that would otherwise have been served by another electric utility or electric cooperative shall not qualify as a measuring point in determining which electric utility or electric cooperative will serve new customers in the future.

(10) The extension of distribution facilities, except as provided in subrules (3), (4), (6), and (7) of this rule, where an extension will be located within 1 mile of another electric utility's or electric cooperative's distribution facilities, shall not be made by an electric utility or electric cooperative without first giving the commission and any affected electric utility or electric cooperative 10 days' notice of its intention by submitting a map showing the location of the proposed new distribution facilities, the location of the prospective

customers, and the location of the facilities of any other electric utility or electric cooperative in the area. If no objections to the proposed extension of distribution facilities are received by the commission within the 10-day notice period, the electric utility or electric cooperative may proceed to construct the facilities. If objections are received, the determination of which electric utility or electric cooperative will extend service may be made the subject of a public hearing and a determination by the commission, upon proper application by any affected party.

(11) The first electric utility or electric cooperative serving a customer pursuant to these rules is entitled to serve the entire electric load on the premises of that customer even if another electric utility or electric cooperative is closer to a portion of the customer's load.

(12) An electric utility or electric cooperative may waive its rights to serve a customer or group of customers if another electric utility or electric cooperative is willing and able to provide the required service and if the commission is notified and has no objections.

(13) Nothing contained in these rules shall be construed to circumvent the requirements of Act No. 69 of the Public Acts of 1929, as amended, being S460.501 et seq. of the Michigan Compiled Laws, or to authorize an electric utility or electric cooperative to extend its service into a municipality then being served by another electric utility or electric cooperative without complying with the provisions of Act No. 69 of the Public Acts of 1929, as amended.

(14) Regardless of other provisions of this rule, except subrule (9), an electric utility or electric cooperative shall not extend service to a new customer in a manner that will duplicate the existing electric distribution facilities of another electric utility or electric cooperative, except where both electric utilities or electric cooperatives are within 300 feet of the prospective customer. Three-phase service does not duplicate single-phase service when extended to serve a 3-phase customer.

(15) The first electric utility or electric cooperative to serve a customer in a new subdivision under the other provisions of this rule has the right to serve the entire subdivision. In extending service to reach the subdivision, the electric utility or electric cooperative shall not duplicate the existing facilities of another electric utility or electric cooperative.

(16) Regardless of any other provisions in these rules, an existing industrial customer that meets the characteristics listed in (a) – (d) below that desires to change electric providers shall be entitled to a one-hour meeting that meets the characteristics shown in (e) – (i) below.

(a) The existing industrial customer must meet the characteristics of the industrial classification manual, division D, manufacturing.

(b) The existing industrial customer currently has a connected load of more than 500 kilowatts.

(c) The existing industrial customer is currently being served with 3-phase electric service.

(d) The existing industrial customer is located within five miles of any three-phase facilities owned and operated by the non-incumbent electric utility or electric cooperative.

(e) The meeting attendees shall include the customer, the electric utility or electric cooperative currently serving the customer, and the electric utility or electric cooperative from whom the customer wishes to take service.

(f) The discussion at the meeting shall be the customer's proposal to switch providers.

(g) If all meeting attendees agree, the meeting may take place via telecommunications.

(h) The meeting shall take place within sixty days of the customer's request for the meeting.

(i) The customer shall be entitled to at least one meeting in a three-year period. Additional meeting requests during the three-year period may be denied by the incumbent electric utility or electric cooperative, the non-incumbent electric utility or electric cooperative, or both.

Whether the incumbent electric utility or electric cooperative waives its right to serve pursuant to subrule (12) of this rule is entirely at the discretion of the incumbent electric utility or electric cooperative and its decision shall be provided to the customer within sixty days of the meeting. Any facilities that are constructed to serve an existing industrial customer that has switched providers shall not qualify as a measuring point in determining which electric utility or electric cooperative will serve new customers in the future.

History: 1983 AACS; 1996 AACS.

PART 5. ENGINEERING

R 460.3501 Electric plant; construction, installation, maintenance, and operation pursuant to good engineering practice required.

Rule 501. The electric plant of the electric utility or electric cooperative shall be constructed, installed, maintained, and operated pursuant to accepted good engineering practice in the electric industry to ~~assure~~ ensure, as far as reasonably possible, continuity of service, uniformity in the quality of service furnished, and the safety of persons and property.

History: 1983 AACS.

R 460.3502 Standards of good practice; adoption by reference.

Rule 502. In the absence of specific rules of the commission, an electric utility or electric cooperative shall apply the standards of accepted good practice that are adopted by reference in R 460.811 et seq.

History: 1983 AACS; 1988 AACS; 1996 AACS.

R 460.3503 Electric ~~U~~utility or electric cooperative plant capacity.

Rule 503. The electric capacity regularly available from all sources shall be large enough to meet all normal demands for service and to provide a reasonable reserve for emergencies.

History: 1983 AACS; 1996 AACS.

R 460.3504 Electric plant inspection program.

Rule 504. Each electric utility or electric cooperative shall adopt a program of inspection of its electric plant to ensure safe and reliable operation. The frequency of the various inspections shall be based on the electric utility's or electric cooperative's experience and accepted good practice. Each electric utility or electric cooperative shall keep sufficient records to verify compliance with its inspection program.

History: 1983 AACS; 1996 AACS.

R 460.3505 Electric ~~U~~utility or electric cooperative line clearance program.

Rule 505. (1) Each electric utility or electric cooperative shall adopt and implement a program of maintaining adequate line clearance through the use of industry-recognized guidelines. A line clearance program shall recognize the national electric safety code standards that are adopted by reference in R 460.811 et seq., ensure safety and reliability, and include the following: ~~The program shall include tree trimming~~.

(a) ~~Tree~~ trimming.

(b) Customer and property owner notifications, including a customer service phone number, not less than 3 days nor more than 90 days prior to planned maintenance tree trimming. Emergent and emergency tree trimming are exempt. Customer and property owner notifications shall include the following:

(i) Personal contact, including an in-person visit with door hanger or phone call, or written notification to persons residing within the target area.

(ii) Personal contact or written notification to local government officials within the target area.

(c) Line clearing statistically relevant representative inspection after line clearing.

History: 1996 AACS.

R 460.3506 Cybersecurity Program.

Rule 506. (1) Each electric utility or electric cooperative shall develop, implement, and maintain a cybersecurity program. At a minimum, the cybersecurity program must include procedures to:

(a) Protect against the unauthorized acquisition, access, use, or disclosure of customer and electric utility or electric cooperative information.

(b) Protect against the unauthorized destruction, degradation, or disruption of electric utility or electric cooperative information or communication systems, networks, or infrastructure.

(c) Identify and mitigate software vulnerabilities.

(d) Implement a least privileged electronic access approach to electric utility or electric cooperative assets and information.

(e) Manage cybersecurity risks relating to vendors and suppliers.

(f) Respond to and recover from a cybersecurity incident as detailed in a cybersecurity incident response plan.

(g) Determine appropriate training requirements for cybersecurity staff and ensure they are met.

(h) Inventory the electric utility's or electric cooperative's information technology and operations technology hardware and software assets.

(2) In addition, each electric utility or electric cooperative shall:

(a) Conduct annual assessments of the cybersecurity program using the National Institute of Standards and Technology Cybersecurity Framework, the Department of Energy Cybersecurity Capability Maturity Model, or similar tool.

(b) Conduct an annual exercise to test the procedures to ensure the effectiveness of the program.

(c) At least quarterly, conduct cyber threat simulations, such as phishing, to test employee awareness and responsiveness to cyber threats.

(d) At least annually, conduct cybersecurity awareness and procedure training.

(3) Annually, by March 31, each electric utility or electric cooperative shall file with the commission a written attestation, signed by an officer of the electric utility or electric cooperative who is authorized to manage the operations of the cybersecurity program and on forms suitable to the commission, that the electric utility or electric cooperative maintains a cybersecurity program in compliance with this rule.

PART 6. METERING EQUIPMENT INSPECTIONS AND TESTS

R 460.3601 Customer-requested meter tests.

Rule 601. (1) Upon request by a customer to an electric utility or electric cooperative, an electric utility or electric cooperative shall make a test of the meter serving the customer. Any charge to the customer shall conform with the electric utility's or electric cooperative's filed and approved tariff rates and rules. Provided, however, that the electric utility or electric cooperative need not make more than 1 test in any 12-month period.

(2) The customer, or his or her representative, may be present when his or her meter is tested.

(3) A report of the results of the test shall be made to the customer within a reasonable time after the completion of the test, and a record of the report, together with a complete record of each test, shall be kept on file at the office of the electric utility or electric cooperative.

History: 1983 AACS.

R 460.3602 Meter and associated device inspections and tests; certification of accuracy.

Rule 602. Every meter shall be inspected and tested, and associated device(s) shall be inspected, in the meter shop of the electric utility or electric cooperative, or a meter testing facility certified by the electric utility or electric cooperative, before being placed in service. The accuracy of each meter shall be certified to be within the tolerances permitted by these rules, except that the electric utility or electric cooperative may rely on the certification of accuracy by the manufacturer on all new meters.

History: 1983 AACS; 2008 AACS.

R 460.3603 Meters with transformers; post-installation inspection; exception.

Rule 603. Meters with associated instrument transformers ~~and phase shifting transformers~~ shall be inspected to determine the proper operation and wiring connections. Inspections shall be made within 60 days after installation by a qualified person who, when possible, should be someone other than the original installer. All ~~self-contained,~~ socket-type meters are excluded from post-installation inspections, except that the original installation shall be inspected when the meter is installed.

History: 1983 AACS.

R 460.3604 Meters and associated devices; removal tests.

Rule 604. All meters and associated devices shall be tested after they are removed from service unless they are retired because of obsolescence.

History: 1983 AACS; 1995 AACS.

R 460.3605 Metering electrical quantities.

Rule 605. (1) All electrical quantities that are to be metered ~~as provided in R 460.3301~~ must be metered by commercially acceptable instruments which are owned and maintained by the electric utility or electric cooperative.

(2) Every reasonable effort must be made to measure at 1 point all the electrical quantities necessary for billing a customer under a given rate.

(3) ELECTRO-MECHANICAL: Metering facilities located at any point where energy may flow in either direction and where the quantities measured are used for billing purposes shall consist of meters equipped with ratchets or other devices to prevent reverse registration and shall be so connected as to separately meter the energy flow in each direction, unless used to implement an electric utility or electric cooperative tariff approved by the commission for service provided under a net metering program.

(4) ELECTRO-MECHANICAL: An electric utility or electric cooperative shall not employ reactive metering for determining the average power factor for billing purposes where energy may flow in either direction or where the customer may generate an appreciable amount of his or her energy requirements at any time, unless suitable directional relays and ratchets are installed to obtain correct registration under all conditions of operation.

(5) ELECTRO-MECHANICAL: All electric service of the same type rendered by an electric utility or electric cooperative under the same rate schedule must be metered with instruments having like characteristics, except that the commission may be requested to approve the use of instruments of different types if their use does not result in unreasonable discrimination. Either all of the reactive meters which may run backwards or none of the reactive meters used for measuring reactive power under 1 schedule must be ratcheted. This rule is only applicable to equipment owned by the electric utility or electric cooperative.

History: 1983 AACS; 2008 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3606 Nondirect reading meters and meters operating from instrument transformers; ~~marking of multiplier on instruments; marking of charts and magnetic tapes; marking of register ratio on meter registers;~~ watthour constants.

Rule 606. (1) Meters that are not direct reading and meters operating from instrument transformers must have the multiplier plainly marked on the dial of the instrument or otherwise suitably marked. ~~All charts and magnetic tapes taken from recording meters must be marked with the date of the record, the meter number, customer, and chart multiplier, except as in R 460.3304.~~

~~(2) The register ratio must be marked on all meter registers.~~

~~(3)~~ (2) The watthour constant (K sub h) for the meter itself must be displayed ~~shown~~ on all watthour meters nameplates.

History: 1983 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3607 Watt-hour meter requirements.

Rule 607. (1) Watthour meters that are used for measuring electrical quantities supplied shall conform to ANSI C12.1 or C12.20 specifications and meet all of the following requirements:

(a) Be of proper design for the circuit on which the meters are used; be in good mechanical and electrical condition; and have adequate insulation, correct internal connections, and correct register.

(b) ELECTRO-MECHANICAL: Not creep at no load with all load wires disconnected at a rate of one complete revolution of the moving element in ten minutes when potential is impressed.

(c) Be accurate to within plus or minus 1.0% for electro-mechanical meters and 0.8% for solid state meters, referred to the portable standard watthour meter as a base, at two unity power factor loads: light load (L.L.) ~~(l.l.)~~ and full ~~heavy~~ load (F.L.) ~~(h.l.)~~.

~~Meter Must be Accurate within ± 1.0% to Portable Standard~~			
Meter Class	Light Load Test Amperes	Heavy Load Test Amperes	Inductive Load 50% Lagging Power Factor Test Amperes
Self-Contained	10% Rated Test Amperes of Meter	~~75~~ 100% Rated Test Amperes of Meter	~~75~~ 100% Rated Test Amperes of Meter
Transformer Rated	~~5~~ 10% Rated Test Amperes of Meter	~~75~~ 100% Rated Test Amperes of Meter	~~75~~ 100% Rated Test Amperes of Meter

(d) Be accurate to within plus or minus 2.0% for electro-mechanical meters and 1.6% for solid state meters, referred to the portable standard watthour meter as a base, at inductive load (I.L.) ~~(i.l.)~~.

(2) Polyphase meters shall have their elements in balance within 2.0% for electro-mechanical meters and 1.6% for solid state meters at rated test amperes at unity power factor and at approximately 50% lagging power factor.

~~(3) Meters that are used with instrument transformers shall be adjusted so that the overall accuracy of the metering installation meets the requirements of this rule.~~

~~(4) Meters and associated devices shall be adjusted as close as practical to zero error and within the accuracy limits specified in subrule (1)(c) of this rule.~~

History: 1983 AACS; 2008 AACS.

~~**R 460.3608 Demand meters, registers, and attachments; requirements.**~~

~~Rule 608. A meter that records, or is capable of recording electric demand, is subject to the requirements of this rule. A demand meter, demand register, or demand attachment that is used to measure a customer's service shall meet all of the following requirements:~~

~~(a) Be in good mechanical and electrical condition.~~

~~(b) Have proper constants, indicating scale, contact device, recording tape or chart, and~~

~~resetting device.~~

~~(c) Not register at no load.~~

~~(d) Curve-drawing meters that record quantity-time curves and integrated-demand meters must be accurate to within plus or minus 2.0% of full scale throughout their working range. Timing elements measuring specific demand intervals must be accurate to within plus or minus 2.0%, and the timing element which serves to provide a record of the time of day when the demand occurs must be accurate to within plus or minus 4 minutes in 24 hours.~~

History: 1983 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3609 Instrument transformers used in conjunction with metering equipment; requirements~~; phase shifting transformers; secondary voltage~~.

Rule 609. (1) Instrument transformers used in conjunction with metering equipment to measure a customer's service shall meet both of the following requirements:

(a) Be in proper mechanical condition and have satisfactory electrical insulation for the service on which used.

(b) Instrument transformers shall meet minimum metering accuracy class 0.3 as defined in IEEE/ANSI C57.13-2016 or accuracy class 0.15 as defined in IEEE Std. C57.13.6-2005. ~~Have characteristics such that the combined inaccuracies of all transformers supplying 1 or more meters in a given installation will not exceed the percentages listed in the following chart:~~

	~~100% Power~~		~~50%~~	
	~~Factor~~		~~Power Factor~~	
~~Current~~	~~10%~~	~~100%~~	~~10%~~	~~100%~~
~~Error 1%~~	~~0.75%~~	~~3%~~	~~2%~~	

~~(2) Meters that are used in conjunction with instrument transformers shall be adjusted so that the overall accuracies will come within the limits specified in this part.~~

~~(3) Instrument transformers shall be tested with the meter with which they are associated by making an overall test or may be checked separately. If the transformers are tested separately, the meters shall also be checked to see that the overall accuracy of the installation is within the prescribed accuracy requirements. (See R 460.3613 (6).)~~

~~(4)~~ (2) The results of tests of instrument transformers shall be kept on record and shall be available for use.

~~(5) Phase shifting transformers shall have secondary voltages under balanced line voltage conditions within plus or minus 1.0% of the voltage impressed on the primary side of the transformer.~~

History: 1983 AACS; 2008 AACS.

R 460.3610 Portable indicating voltmeters; accuracy.

Rule 610. All portable indicating voltmeters that are used for determining the quality of service voltage to customers shall be checked against a suitable secondary reference standard at least once every 6 months for electro-mechanical ~~analog~~ devices, and once every 12 months for solid state ~~digital~~ devices. The accuracy of these voltmeters shall be rated so that the error of the indication is not more than plus or minus 1% of full scale. If the portable indicating voltmeter is found to be in error by more than the rated accuracy at commonly used scale deflections, it shall be adjusted.

History: 1983 AACS; 2008 AACS.

R 460.3611 Meter testing equipment; availability; provision and use of primary standards.

Rule 611. (1) An electric utility or electric cooperative shall maintain sufficient laboratories, meter testing shops, secondary standards, instruments, and facilities to determine the accuracy of all types of meters and measuring devices used by the electric utility or electric cooperative. The electric utility or electric cooperative may, if necessary, have all or part of the required tests made, or its portable testing equipment checked, by another electric utility or electric cooperative or agency which uses standards with traceable accuracies to the United States National Institute of Standards and Technology (NIST) or National Research Council (NRC) Canada ~~is approved by the commission~~ and which has adequate and sufficient testing equipment to comply with these rules if approved by the commission.

(2) At a minimum, an electric utility or electric cooperative shall keep all of the following testing equipment available:

(a) One or more portable standard watthour meters that has a capacity and voltage range which is adequate to test all watthour meters used by the electric utility or electric cooperative.

(b) Portable indicating instruments that are necessary to determine the accuracy of all instruments used by the electric utility or electric cooperative.

(c) One or more secondary standards to check each of the various types of portable standard watthour meters used for testing watthour meters. Each secondary standard shall consist of an approved portable standard watthour meter which is kept permanently at 1 point and which is not used for fieldwork. Standards shall be well- compensated for both classes of temperature errors, shall be practically free from errors due to ordinary voltage variations, and shall be free from erratic registration due to any cause.

(d) Suitable standards, which are not used for fieldwork, to check portable instruments used in testing.

(3) An electric utility or electric cooperative shall provide and use primary standards that have accuracies which are traceable to the United States National Institute of Standards and Technology (NIST) or National Research Council (NRC) Canada.

History: 1983 AACS; 1995 AACS.

R 460.3612 Test standards; accuracy.

Rule 612. (1) The accuracies of all primary reference standards shall be certified as traceable to the National Institute of Standards and Technology (NIST) or National Research Council (NRC) Canada, either directly or through other recognized standards laboratories. These standards shall have their accuracy certified at the time of purchase. Standard cells shall be intercompared regularly and at least 1 standard cell shall be checked by a standardizing laboratory at intervals of not more than 2 years. Reference standards of resistance, potentiometers, and volt boxes shall be checked at intervals of not more than 3 years.

(2) Secondary watthour meter standards shall not be in error by more than plus or minus 0.3% at loads and voltages at which they are to be used, and shall not be used to check or calibrate working standards, unless the secondary standard has been checked and adjusted, if necessary, within the preceding 6 months. Each secondary standard watthour meter shall have calibration data available and shall have a history card.

(3) Secondary standards indicating instruments shall not be in error by more than plus or minus 0.5% of indication at commonly used scale deflection and shall not be used to check or calibrate portable indicating instruments, unless the secondary standard has been checked and adjusted, if necessary, within the preceding 12 months. A calibration record shall be maintained for each standard.

(4) Regularly used working portable standard watthour meters shall be compared with a secondary standard at least once every 6 months. Infrequently used working standards shall be compared with a secondary standard before they are used.

(5) Working portable standard watthour meters shall be adjusted so that their percent registration is within 99.7% and 100.3% at 100% power factor and within 99.5% and 100.5% at 50% lagging power factor at all voltages and loads at which the standard may be used. A history and calibration record shall be kept for each working standard.

(6) The meter accuracies required in this rule for all primary, secondary, and working standards shall be referred to 100%. Service measuring equipment shall be adjusted to within the accuracies required assuming the portable test equipment to be 100% accurate with the calibration correction taken into consideration.

History: 1983 AACS; 1995 AACS; 2008 AACS.

R 460.3613 Solid state ~~M~~meter and metering equipment testing requirements.

Rule 613. (1) The testing of any unit of metering equipment must consist of a comparison of its accuracy with a standard of known accuracy. Units that are not properly connected or that do not meet the accuracy or other requirements of these meter and metering equipment rules at the time of testing shall be reconnected or rebuilt to meet such requirements and must be adjusted to within the required accuracy and as close to zero error as practicable or else their use shall be discontinued.

(2) All solid state single-phase, three-phase, network, self-contained and transformer rated ~~Self-contained, electro-mechanical, solid state, single-phase, and all network~~ meters must be in compliance with all of the following requirements:

(a) Be checked for accuracy as provided for in R 460.3602.

(b) Notwithstanding the provisions of subdivision (a) of this subrule, upon application to the commission and upon receipt of an order granting approval, the testing of self-contained, ~~electro-mechanical,~~ solid state, single-phase, ~~and~~ all network meters, and all self-contained and transformer-rated, solid state, 3-phase meters in service must be governed by a quality control plan as follows:

(i) Meters must be divided into homogenous groups by manufacturers' types, and certain manufacturers' types must be further subdivided into separate groups by manufacturers' serial numbers.

(ii) The meters in each homogeneous group must then be further subdivided into lots of not less than 301, and not more than 35,000, meters each, except that meters of the most recent design may be combined into lots regardless of manufacturers' type, except that where the number of meters of a single type is 8,001 or more, that number of meters must be segregated by types for the formation of lots.

(iii) From each assembled lot, a sample of the size specified in table A-2, ANSI/ASQ~~C~~ Z1.9-2003(R2018) using general inspection level II, must be drawn annually. The sample must be drawn at random.

(iv) The meters in each sample must be tested for accuracy pursuant to paragraphs (v) to (xi) of this subdivision.

(v) The test criteria for acceptance or rejection of each lot must be based on the test at heavy load only and must be that designated for double specification limits and an acceptable quality level (AQL) that is not higher than 2.50 (normal inspection) as shown in table B-3, ANSI/ASQ~~C~~ Z1.9-2003(R2018).

(vi) The necessary calculations must be made pursuant to Example B-3 of ANSI/ASQ~~C~~ Z1.9-2003(R2018). The upper and lower specification limits, U and L, must be 102% and 98%, respectively.

(vii) A lot must be rejected if the total estimated percent defective (p) exceeds the appropriate maximum allowable percent defective (M) as determined from table B-3 as specified in paragraph (v) of this subdivision.

(viii) All meters in a rejected lot must be tested within a maximum period of 60 months and be adjusted pursuant to the provisions of R 460.3607 or be replaced with meters that are in compliance with the requirements of R 460.3607.

(ix) During each calendar year, new meter samples must be drawn as specified in this subdivision from all meters in service, with the exception that lots that have been rejected must be excluded from the sampling procedure until all meters included in the rejected lots have been tested.

(x) The electric utility or electric cooperative may elect to adopt the following sample plan for lots that have been rejected the previous year.

(a) From rejected lots, a sample of the lot size specified in table A-2, ANSI/ASQ Z1.9-2003(R2018) using general inspection level III, must be drawn at random**.**

(b) The test criteria for acceptance or rejection of each lot must be based on the test at heavy load and must be that designated for double specification limits and an acceptable quality level (AQL) that is not higher than 2.50 (tightened inspection) as shown in Table B-3 of ANSI/ASQ Z1.9-2003(R2018).

(c) The necessary calculations must be made pursuant to Example B-3 of ANSI/ASQ Z1.9-2003(R2018). The upper and lower specification limits, U and L, must be 102% and 98% respectively.

(d) A lot must be rejected if the total estimated percent defective (p) exceeds the appropriate maximum allowable percent defective (M) as determined from Table B-3 specified in paragraph (b) of this subdivision. If the acceptability criteria of the sampling plan are met, then the lot shall be considered acceptable and shall be returned to the variables sampling plan the following year. If the acceptability criteria of the sampling plan are not met, then the electric utility or electric cooperative shall reject that lot and all meters in that lot must be tested and adjusted or replaced within a maximum period of 48 months after the second rejection

(xi) The electric utility or electric cooperative must adhere to the quality control plan switching procedures as described below:

(a)Tightened to Normal: When tightened inspection is in effect, normal inspection shall be instituted when all lots have been considered acceptable on original inspection in preceding two years. The electric utility or electric cooperative must adhere to quality control plan as provided in R 460.3613(2)(b).

(b) Normal to Reduced: When normal inspection is in effect, reduced inspection shall be instituted providing that all of the following conditions are satisfied.

(i) The normal inspection is in effect for the preceding three years.

(ii) All lots of same manufacturer meter type have been accepted on normal inspection in preceding three years. The reduced inspection must adhere to a quality plan as follows.

(iii) All in service meters must be divided into homogenous groups by manufacturers' types, and certain manufacturers' types must be further subdivided into separate groups by manufacturers' serial numbers.

(iv) The meters in each homogeneous group must then be further subdivided into lots of not less than 301, and not more than 35,000, meters each, except that meters of the most recent design may be combined into lots regardless of manufacturers' type, except that where the number of meters of a single type is 8,001 or more, that number of meters must be segregated by types for the formation of lots.

(v) From each assembled lot, a sample of the lot size specified in table A-2, ANSI/ASQ Z1.9-2003(R2018) using general inspection level I, must be drawn annually. The sample must be drawn at random.

(vi) The meters in each sample must be tested for accuracy pursuant to paragraphs (v) to (ix) of this subdivision.

(vii) The test criteria for acceptance or rejection of each lot must be based on the test at heavy load only and must be that designated for double specification limits and an acceptable quality level (AQL) that is not higher than 2.50 (reduced inspection) as shown in table B-4, ANSI/ASQ Z1.9-2003(R2018).

(viii) The necessary calculations must be made pursuant to Example B-3 of ANSI/ASQ Z1.9-2003(R2018). The upper and lower specification limits, U and L, must be 102% and 98%, respectively.

(ix) A lot must be rejected if the total estimated percent defective (p) exceeds the appropriate maximum allowable percent defective (M) as determined from table B-4 as specified in paragraph (v) of this subdivision.

(c) Reduced to Normal: When reduced inspection is in effect, normal inspection shall be instituted if a lot is rejected on original inspection. The normal inspection is invoked. The electric utility or electric cooperative must adhere to quality control plan as provided in R 460.3613(2)(b).

(i) Continuation of Inspection: Normal, tightened, or reduced inspection shall continue unchanged except where the above switching procedures require change.

(3) The quality control plan specified in R 460.3613(2)(b) does not alter the rules under which customers may request special tests of meters.

(4) All solid-state meters must be in compliance with all of the following requirements:

(a) Be checked for accuracy in all of the following situations:

(i) When a meter is suspected of being inaccurate or damaged.

(ii) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)

(b) Be inspected for electrical faults when the accuracy of the device is checked.

(c) Have the connections to the customer's circuits checked when the meter is tested on the premises or when removed for testing.

(d) A meter need not be tested or checked for any reason if the device was tested and checked within the previous 12 months except when a complaint is received.

(5) All transformer rated solid state meters must be in compliance with all of the following requirements:

(a) Be checked for accuracy at unity and 50% power factor on the customer's premises within 60 days after installation, unless the transformers are in compliance with the specifications outlined in the American National Standards Institute standard ANSI C-57.13.

(b) Have the connections to the customer's circuits and multipliers checked when the equipment is tested for accuracy on the premises or when removed for testing and when instrument transformers are changed.

~~(x) The utility may elect to adopt a mixed variables-attributes sampling plan as outlined in Section A9 of ANSI/ASQC Z1.9, in which case, a lot that is not in compliance with the acceptability criteria of the variables sampling plan shall be resampled the following year using an attributes sampling plan. If the acceptability criteria of the attributes sampling plan are met, then the lot shall be considered acceptable and shall be returned to the variables sampling plan the following year. If the acceptability criteria of the attributes sampling plan are not met, then the utility shall reject that lot and all meters in the lot must be tested and adjusted or replaced within a maximum period of 48 months after the second rejection.~~

~~(xi) The plan specified in paragraph (x) of this subdivision does not alter the rules under which customers may request special tests of meters.~~

~~(c) Be checked for accuracy in all of the following situations:~~

~~(i) When a meter is suspected of being inaccurate or damaged.~~

~~(ii) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)~~

~~(d) Be inspected for mechanical and electrical faults when the accuracy of the device is checked.~~

~~(e) Have the register and the internal connections checked before the meter is first placed in service and when the meter is repaired.~~

~~(f) Have the connections to the customer's circuits checked when the meter is tested on the premises or when removed for testing.~~

~~(g) A meter need not be tested or checked for any reason if the device was tested, checked, and adjusted within the previous 12 months except when a complaint is received.~~

~~(3) All single-phase instrument rated electro-mechanical meters must be in compliance with all of the following requirements:~~

~~(a) Be checked for accuracy at unity power factor at the point where a meter is installed, at a central testing point, or in a mobile testing laboratory as follows:~~

~~(i) Not later than 9 months after 144 months of service for a surge-resistant meter and not later than 9 months after 96 months of service for a non-surge-resistant meter.~~

~~(ii) When a meter is suspected of being inaccurate or damaged.~~

~~(iii) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)~~

~~(iv) Before use when a meter has been inactive for more than 1 year after having~~

~~been in service.~~

~~(b) Be inspected for mechanical and electrical faults when the accuracy of the device is checked.~~

~~(c) Have the register and the internal connections checked before the meter is first placed in service and when the meter is repaired.~~

~~(d) Have the connections to the customer's circuits checked when the meter is tested on the premises or when removed for testing.~~

~~(e) Be checked for accuracy at 50% power factor when purchased and after rebuilding.~~

~~(f) A meter need not be tested or checked for any reason if the device was tested, checked, and adjusted within the previous 12 months except when a complaint is received.~~

~~(4) All self-contained electro-mechanical and solid state 3-phase meters and associated equipment must be in compliance with all of the following requirements. However, a utility may elect to include self-contained solid state 3-phase meters in service in its quality control plan as provided for in R 460.3613(2)(b). Therefore, a utility may be exempt from the periodic meter test requirements as provided in subdivision (a)(ii) of this subrule.~~

~~(a) Be tested for accuracy at unity and 50% power factor as follows:~~

~~(i) Before being placed in service.~~

~~(ii) Not later than 9 months after 120 months of service.~~

~~(iii) When a meter is suspected of being inaccurate or damaged.~~

~~(iv) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)~~

~~(v) When a meter is removed and put back in service.~~

~~(b) Be inspected for mechanical and electrical faults when the accuracy is checked.~~

~~(c) Have the register and internal connections checked before the meter is first installed, when repaired and when the register is changed.~~

~~(d) Have the connections to the customer's circuits and multipliers checked when the equipment is tested for accuracy on the customer's premises.~~

~~(5) All transformer-rated electro-mechanical and solid state 3-phase meters and associated equipment must be in compliance with all of the following requirements. However, a utility may elect to include transformer-rated solid state 3-phase meters in service in its quality control plan as provided for in R 460.3613(2)(b). Therefore, a utility may be exempt from the periodic meter test requirements as provided in subdivision (a)(iii) of this subrule.~~

~~(a) Be checked for accuracy at unity and 50% power factor as follows:~~

~~(i) Before being placed in service.~~

~~(ii) On the customer's premises within 60 days after installation, unless the transformers are in compliance with the specifications outlined in the American National Standards Institute standard ANSI C-57.13, and unless the meter adjustment limits do not exceed plus or minus 1.5% at 50% power factor.~~

~~(iii) Not later than 9 months after 72 months of service.~~

~~(iv) When a meter is suspected of being inaccurate or damaged.~~

~~(v) When the accuracy is questioned by a customer. (See R 460.3601.)~~

~~(vi) When a meter is removed and put back in service.~~

~~(b) Be inspected for mechanical and electrical faults when the accuracy is checked.~~

~~(c) Have the register and internal connections checked before the meter is first placed in service and when the meter is repaired.~~

~~(d) Have the connections to the customer's circuits and multipliers checked when the equipment is tested for accuracy on the premises or when removed for testing and when instrument transformers are changed.~~

~~(e) Be checked for accuracy at 50% power factor when purchased and after rebuilding.~~

~~(6) A utility shall test instrument transformers in all of the following situations:~~

~~(a) When first received, unless a transformer is accompanied by a certified test report by the manufacturer.~~

~~(b) When removed and put back in service.~~

~~(c) Upon complaint.~~

~~(d) When there is evidence of damage.~~

~~(e) When an approved check, such as the variable burden method in the case of current transformers that is made when the meter is tested indicates that a quantitative test is required.~~

~~(7) Demand meters must be in compliance with both of the following requirements:~~

~~(a) Be tested for accuracy in all of the following situations:~~

~~(i) Before a meter is placed in service.~~

~~(ii) When an associated meter is tested and the demand meter is a block interval nonrecording type or a thermal type.~~

~~(iii) After 2 years of service if the meter is of the recording type, but testing is not required if the meter is of the pulse-operated type and the demand reading is checked with the kilowatt-hour reading each billing cycle.~~

~~(iv) When a meter is suspected of being inaccurate or damaged.~~

~~(v) When the accuracy is questioned by a customer. (See R 460.3601.)~~

~~(b) Be inspected for mechanical and electrical faults when a meter is tested in the field or in the meter shop.~~

History: 1983 AACS; 1995 AACS; 2008 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3613a Electro-mechanical meter and metering equipment testing requirements.

Rule 613. (1) The testing of any unit of metering equipment must consist of a comparison of its accuracy with a standard of known accuracy. Units that are not properly connected or that do not meet the accuracy or other requirements of these meter and metering equipment rules at the time of testing shall be reconnected or rebuilt to meet such requirements and must be adjusted to within the required accuracy and as close to zero error as practicable or else their use shall be discontinued.

(2) Self-contained, electro-mechanical, combination electro-mechanical and solid state, single-phase, and all network meters must be in compliance with all of the following requirements:

(a) Be checked for accuracy as provided for in R 460.3602.

(b) Notwithstanding the provisions of subdivision (a) of this subrule, upon application to the commission and upon receipt of an order granting approval, the testing of self-contained, electro-mechanical, solid state, single-phase, and all network meters in service must be governed by a quality control plan as follows:

(i) Meters must be divided into homogenous groups by manufacturers' types, and certain manufacturers' types must be further subdivided into separate groups by manufacturers' serial numbers.

(ii) The meters in each homogeneous group must then be further subdivided into lots of not less than 301, and not more than 35,000, meters each, except that meters of the most recent design may be combined into lots regardless of manufacturers' type, except that where the number of meters of a single type is 8,001 or more, that number of meters must be segregated by types for the formation of lots.

(iii) From each assembled lot, a sample of the size specified in table A-2, ANSI/ASQ Z1.9-2003(R2018), must be drawn annually. The sample must be drawn at random.

(iv) The meters in each sample must be tested for accuracy pursuant to paragraphs (v) to (xi) of this subdivision.

(v) The test criteria for acceptance or rejection of each lot must be based on the test at heavy load only and must be that designated for double specification limits and an acceptable quality level (AQL) that is not higher than 2.50 (normal inspection) as shown in table B-3, ANSI/ASQ Z1.9-2003(R2018).

(vi) The necessary calculations must be made pursuant to Example B-3 of ANSI/ASQ Z1.9-2003(R2018). The upper and lower specification limits, U and L, must be 102% and 98%, respectively.

(vii) A lot must be rejected if the total estimated percent defective (p) exceeds the appropriate maximum allowable percent defective (M) as determined from table B-3 as specified in paragraph (v) of this subdivision.

(viii) All meters in a rejected lot must be tested within a maximum period of 60 months and be adjusted pursuant to the provisions of R 460.3607 or be replaced with meters that are in compliance with the requirements of R 460.3607.

(ix) During each calendar year, new meter samples must be drawn as specified in this subdivision from all meters in service, with the exception that lots that have been rejected must be excluded from the sampling procedure until all meters included in the rejected lots have been tested.

(x) The electric utility or electric cooperative may elect to adopt the following sample plan for lots that have been rejected the previous year.

(a) From each rejected lot, a sample of the lot size specified in table A-2, ANSI/ASQ Z1.9-2003(R2018) using general inspection level III, must be drawn at random.

(b) The test criteria for acceptance or rejection of each lot must be based on the test at heavy load and must be that designated for double specification limits and an acceptable quality level (AQL) that is not higher than 2.50 (tightened inspection) as shown in Table B-3 of ANSI/ASQ Z1.9-2003(R2018).

(c) The necessary calculations must be made pursuant to Example B-3 of ANSI/ASQ Z1.9-2003(R2018). The upper and lower specification limits, U and L, must be 102% and 98% respectively.

(d) A lot must be rejected if the total estimated percent defective (p) exceeds the appropriate maximum allowable percent defective (M) as determined from Table B-3 specified in paragraph (b) of this subdivision. If the acceptability criteria of the sampling plan are met, then the lot shall be considered acceptable and shall be returned to the variables sampling plan the following year. If the acceptability criteria of the sampling plan are not met, then the electric utility or electric cooperative shall reject that lot and all meters in that lot must be tested and adjusted or replaced within a maximum period of 48 months after the second rejection

(xi) The plan specified in paragraph (x) of this subdivision does not alter the rules under which customers may request special tests of meters.

(c) Be checked for accuracy in all of the following situations:

(i) When a meter is suspected of being inaccurate or damaged.

(ii) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)

(d) Be inspected for mechanical and electrical faults when the accuracy of the device is checked.

(e) Have the register and the internal connections checked before the meter is first placed in service and when the meter is repaired.

(f) Have the connections to the customer's circuits checked when the meter is tested on the premises or when removed for testing.

(g) A meter need not be tested or checked for any reason if the device was tested, checked, and adjusted within the previous 12 months except when a complaint is received.

(3) All single-phase transformer rated electro-mechanical meters must be in compliance with all of the following requirements:

(a) Be checked for accuracy at unity power factor at the point where a meter is installed, at a central testing point, or in a mobile testing laboratory as follows:

(i) Not later than 9 months after 144 months of service for a surge-resistant meter and not later than 9 months after 96 months of service for a non-surge-resistant meter.

(ii) When a meter is suspected of being inaccurate or damaged.

(iii) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)

(iv) Before use when a meter has been inactive for more than 1 year after having been in service.

(b) Be inspected for mechanical and electrical faults when the accuracy of the device is checked.

(c) Have the register and the internal connections checked before the meter is first placed in service and when the meter is repaired.

(d) Have the connections to the customer's circuits checked when the meter is tested on the premises or when removed for testing.

(e) Be checked for accuracy at 50% power factor when purchased and after rebuilding.

(f) A meter need not be tested or checked for any reason if the device was tested, checked, and adjusted within the previous 12 months except when a complaint is received.

(4) All self-contained electro-mechanical, combination electro-mechanical and solid-state, 3-phase meters and associated equipment must be in compliance with all of the following requirements. However, an electric utility or electric cooperative may elect to include self-contained solid state 3-phase meters in service in its quality control plan as provided for in R 460.3613(2)(b). Therefore, an electric utility or electric cooperative may be exempt from the periodic meter test requirements as provided in subdivision (a)(ii) of this subrule.

(a) Be tested for accuracy at unity and 50% power factor as follows:

(i) Before being placed in service.

(ii) Not later than 9 months after 120 months of service.

(iii) When a meter is suspected of being inaccurate or damaged.

(iv) When the accuracy of a meter is questioned by a customer. (See R 460.3601.)
(v) When a meter is removed and put back in service.
(b) Be inspected for mechanical and electrical faults when the accuracy is checked.
(c) Have the register and internal connections checked before the meter is first installed, when repaired and when the register is changed.
(d) Have the connections to the customer's circuits and multipliers checked when the equipment is tested for accuracy on the customer's premises.

(5) All transformer-rated electro-mechanical, combination electro-mechanical and solid state, 3-phase meters and associated equipment must be in compliance with all of the following requirements. However, an electric utility or electric cooperative may elect to include transformer-rated solid state 3-phase meters in service in its quality control plan as provided for in R 460.3613(2)(b). Therefore, an electric utility or electric cooperative may be exempt from the periodic meter test requirements as provided in subdivision (a)(iii) of this subrule.
(a) Be checked for accuracy at unity and 50% power factor as follows:
(i) Before being placed in service.
(ii) On the customer's premises within 60 days after installation, unless the transformers are in compliance with the specifications outlined in the American National Standards Institute standard ANSI C-57.13, and unless the meter adjustment limits do not exceed plus or minus 1.5% at 50% power factor.
(iii) Not later than 9 months after 72 months of service.
(iv) When a meter is suspected of being inaccurate or damaged.
(v) When the accuracy is questioned by a customer. (See R 460.3601.)
(vi) When a meter is removed and put back in service.
(b) Be inspected for mechanical and electrical faults when the accuracy is checked.
(c) Have the register and internal connections checked before the meter is first placed in service and when the meter is repaired.
(d) Have the connections to the customer's circuits and multipliers checked when the equipment is tested for accuracy on the premises or when removed for testing and when instrument transformers are changed.
(e) Be checked for accuracy at 50% power factor when purchased and after rebuilding.

R 460.3614 Standards check by the commission.

Rule 614. (1) Upon request of the commission, an electric utility or electric cooperative shall submit 1 of its portable standard watthour meters and 1 portable indicating voltmeter, ammeter, and wattmeter to a commission-approved standards laboratory for checking of their accuracy.

(2) An electric utility or electric cooperative shall normally check its own working portable standard watthour meters or instruments against primary or secondary standards and shall calibrate these working standards or instruments before they are submitted with a record of such calibration attached to each of the working standards or instruments.

History: 1983 AACS.

R 460.3615 Metering equipment records.

Rule 615. (1) An electric utility or electric cooperative shall maintain a complete record of the most recent test of all metering equipment. The record must show all of the following information:

(a) Identification and location of unit.

(b) Equipment with which the device is associated.

(c) The date of test.

(d) Reason for the test.

(e) Readings before and after the test.

(f) ELECTRO-MECHANICAL: A statement as to whether or not the meter creeps and, in case of creeping, the rate.

(g) A statement of meter accuracies before and after adjustment sufficiently complete to permit checking of the calculations employed.

(h) Indications showing that all required checks have been made.

(i) A statement of repairs made, if any.

(j) Identification of the testing standard and the person making the test.

(k) Communications type.

(l) Firmware.

(2) The electric utility or electric cooperative shall also keep a record of each unit of metering equipment which shows all of the following information:

(a) When the unit was purchased.

(b) The unit's cost.

(c) The company's identification.

(d) Associated equipment.

(e) Essential nameplate data.

(f) The date of the last test. The record must also show either the present service location with the date of installation or, if removed from service, the service location from which the unit was removed with the date of removal.

(3) The electric utility or electric cooperative shall maintain records of the necessary calculations made pursuant to Example B-3 of ANSI/ASQ Z1.9 for each sample or resample drawn. In addition to the actual computation, the data shall include all of the following:

(i) The type of meter.

(ii) The number of meters in the lot.

(iii) The meter numbers of sample meters.

(iv) The actual prior-to-adjustment test data of each meter tested.

(v) The number of months since the last test for each meter in the sample.

History: 1983 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3616 Average meter error; determination.

Rule 616. If a metering installation is found upon any test to be in error by more than 2% at any test load, the average error shall be determined in 1 of the following ways:

(a) If the metering installation is used to measure a load which has practically constant characteristics, such as a streetlighting load, the meter shall be tested under similar conditions of load and the accuracy of the meter "as found" shall be considered as the average accuracy.

(b) If a single-phase metering installation is used on a varying load, the average error shall be the weighted algebraic average of the error at light load and the error at heavy load, the latter being given a weighting of 4 times the former.

(c) If a polyphase metering installation is used on a varying load, the average error shall be the weighted algebraic average of its error at light load given a weighting of 1, its error at heavy load and 100% power factor given a weighting of 4, and at heavy load and 50% lagging powerfactor given a weighting of 2.

(d) If a load, other than the light, heavy, and low power factor load specified for routine testing, is more representative of the customary use of the metering equipment, its error at that load shall also be determined. In this case, the average error shall be computed by giving the error at such load and power factor a weighting of 3 and each of the errors at the other loads (light, heavy, and 50% lagging power factor) a weighting of 1. Each error shall be assigned its proper sign.

History: 1983 AACS.

R 460.3617 Reports to be filed with the commission.

Rule 617. (1) An electric utility or electric cooperative shall file, with the commission, on or before the first day of April ~~within 30 days after the first day of January of each year~~, all of the following information covering the 12-month period ending December 31:~~an officer-certified statement that the utility has complied with all of the requirements set forth in these rules relating to meter standardizing equipment.~~

(a) An officer-certified statement that the electric utility or electric cooperative has complied with all of the requirements set forth in these rules relating to meter standardizing equipment.

(b) A meter test report summarizing all rejected lots tested as part of the sampling plan during the preceding calendar year. The report must include the following information for each rejected lot:

(i) Meter manufacturer.

(ii) Meter type.

(iii) Average months in service since the last test.

(iv) Meter lots in tightened inspection.

(c) A meter test report summarizing all rejected meter tests not tested as part of the sampling plan during the preceding calendar year. The report must include the following information for each rejected meter test:

(i) Meter manufacturer.

(ii) Meter type.

(iii) Purchase year.

(iv) As found accuracy or accuracy range.

~~(2) For all meters that are not included in the provisions of R 460.3613(2)(b), the utility shall file, with the commission, on or before the first day of April of each year, its annual tabulation of all of its prior-to-adjustment meter test results covering the 12-month period ending December 31. The utility shall summarize, by meter type, all individual meters~~

~~and overall light and heavy load prior-to-adjustment test results at the power factors required by these rules. The summary shall be divided into~~

~~heavy load 100% power factor, light load 100% power factor, and heavy load 50% power factor test results and shall also be divided according to the length of meter test period and types of single-phase and polyphase meters. The summary shall show the number of meters or overall tests found within each of the following accuracy classifications:~~

~~(a) No recording.~~

~~(b) Creeping.~~

~~(c) Equal to or less than 94.0%. (d) 94.1 to 96.0%.~~

~~(e) 96.1 to 97.0%.~~

~~(f) 97.1 to 98.0%.~~

~~(g) 98.1 to 99.0%.~~

~~(h) 99.1 to 100.0%.~~

~~(i) 100.1 to 101.0%.~~

~~(j) 101.1 to 102.0%.~~

~~(k) 102.1 to 103.0%.~~

~~(l) 103.1 to 104.0%.~~

~~(m) 104.1 to 106.0%.~~

~~(n) Over 106.0%.~~

~~When a utility is subject to multiple state jurisdiction, these accuracy classifications may be modified with the approval of the commission.~~

~~(3) For all meters that are included in the provisions of R 460.3613(2)(b), the utility shall file, with the commission, on or before the first day of April, all of the following information:~~

~~(a) A summary of all samples of meter lots that pass the acceptability criteria as set forth in ANSI/ASQC Z1.9-1980, including complete data on all of the following:~~

~~(i) The type of meter.~~

~~(ii) The number of meters in a lot.~~

~~(iii) The size of the sample.~~

~~(iv) The average months in service since the last test.~~

~~(v) The computed p (total estimated percent defective in lot).~~

~~(vi) The corresponding M (maximum allowable percent defective) as determined from table B-3 in ANSI/ASQC Z1.9-1980.~~

~~(b) The necessary calculations made pursuant to Example B-3 of ANSI/ASQC Z1.9-1980 shall be retained for each sample or resample drawn. In addition to the actual computation, the data shall include all of the following:~~

~~(iv) The type of meter.~~

~~(v) The number of meters in the lot. (iii)The meter numbers of sample meters.~~

~~(vi) The actual prior-to-adjustment test data of each meter tested.~~

~~(vii) The number of months since the last test for each meter in the sample.~~

~~A sample of the calculations and data for a lot that passes the acceptability criteria shall be included in the report to the commission.~~

~~(c) A copy of the complete data, as outlined in this subrule, shall be included for each meter lot that is not in compliance with the acceptability criteria of the sampling plan~~

~~employed as set forth in ANSI/ASQC Z1.9-1980.~~

~~(d) A report summarizing the testing of all meters in rejected lots that are to be returned to service. The heavy load preadjustment tests only shall be recorded, and the accuracy classifications as established in subrule (2) of this rule shall be used. Each rejected lot shall be reported separately and shall be separated into groups by the number of months since the last test as follows:~~

~~(i) 0 to 48 months.~~

~~(ii) 49 to 72 months.~~

~~(iii) 73 to 96 months.~~

~~(iv) More than 96 months.~~

History: 1983 AACS; 1995 AACS.

R 460.3618 Generating and interchange station meter tests; schedule; accuracy limits.

Rule 618. (1) Generating and interchange station and watthour meters shall be tested in conjunction with their associated equipment as follows:

(a) At least once every 24 months for generating station meters.

(b) At least once every 12 months for interchange meters.

(2) The accuracy limits for any particular device shall not be greater than the accuracy limits required elsewhere in these rules.

History: 1983 AACS.

PART 7. STANDARDS OF QUALITY OF SERVICES

R 460.3701 Alternating current systems; standard frequency.

Rule 701. The standard frequency for alternating current systems shall be 60 hertz. The frequency shall be maintained within limits as administered by the regional transmission organization.~~ that will permit the satisfactory operation of customers' clocks which are connected to the system.~~

History: 1983 AACS; 1996 AACS.

R 460.3702 Standard nominal service voltage; limits; exceptions.

Rule 702. (1) Each electric utility or electric cooperative shall adopt and submit standard nominal service voltages.

(2) With respect to secondary voltages, the following provisions shall apply:

(a) For all retail service, the variations of voltage shall be not more than 5% above or below the standard nominal voltage as submitted pursuant to subrule (1) of this rule, except as noted in subrule (4) of this rule.

(b) Where 3-phase service is provided, the electric utility or electric cooperative shall exercise reasonable care to ensure that the phase voltages are balanced within practical tolerances.

(3) With respect to primary voltages, the following provisions shall apply:

(a) For service rendered principally for industrial or power purposes, the voltage variation shall not be more than 5% above or below the standard nominal voltages as submitted pursuant to subrule (1) of this rule, except as noted in subrule (4) of this rule.

(b) The limitations in subdivision (a) of this subrule do not apply to special contracts in which the customer specifically agrees to accept service with unregulated voltage.

(4) Voltages ~~outside~~ above or below the limits specified in subrule (2) and (3) of this rule shall not be considered a violation if the variations are infrequent fluctuations or occur from adverse weather conditions, service interruptions, causes beyond the control of the electric utility or electric cooperative, or voltage reductions that are required to reduce system load at times of supply deficiency or loss of supply.

History: 1983 AACS; 1996 AACS.

R 460.3703 Voltage measurements and records.

Rule 703. (1) An electric utility or electric cooperative shall make voltage measurements at the electric utility's or electric cooperative's substation service terminals and, where permissible, at the electric utility's or electric cooperative's service points.

(2) Each electric utility or electric cooperative shall make a sufficient number of voltage measurements, using recording voltmeters, to determine if voltages are in compliance with the requirements stated in R 460.3702. For installations in which the meter measures voltage ~~variations~~, measurements using recording voltmeters are not necessary unless records of the measurements through the meter are not available.

(3) All records obtained under subrule (2) of this rule must be retained by the electric utility or electric cooperative for not less than 2 years and must be available for inspection by the commission's representatives. The records shall indicate all of the following information:

(a) The location where the voltage was measured.

(b) The time and date of the measurement.

(c) For installations without meters that measure voltage variations, the results of the comparison with an indicating voltmeter at the time a recording meter is set.

(d) Number of customers impacted.

History: 1983 AACS; 1996 AACS; 2019 MR 1, Eff. Jan. 9, 2019.

R 460.3704 Voltage measurements; required equipment; periodic checks; certificate or calibration card for standards.

Rule 704. (1) Each electric utility or electric cooperative shall have access to at least 1 indicating voltmeter that has a stated accuracy within 0.25% of full scale. The instrument shall be maintained within its stated accuracy.

(2) Each electric utility or electric cooperative shall have not less than 2 indicating voltmeters that have a stated accuracy within 1.0% of full scale.

(3) Each electric utility or electric cooperative shall have not less than 2 portable recording voltmeters, or their electronic equivalent, with a stated accuracy within 1.5% of full

scale.

(4) Standards shall be checked in accordance with R 460.3612.

(5) Working instruments shall be checked in accordance with R 460.3610.

(6) Each standard shall be accompanied at all times by a certificate or calibration card, duly signed and dated, on which the corrections required to compensate for errors found at the customary test points at the time of the last test are recorded.

History: 1983 AACS; 1996 AACS.

R 460.3705 Interruptions of service; records; planned interruption; notice to commission.

Rule 705. (1) Each electric utility or electric cooperative shall make a reasonable effort to avoid interruptions of service. When interruptions occur, service shall be restored within the shortest time practical, consistent with safety.

(2) Each electric utility or electric cooperative shall keep records of sustained interruptions of service to its customers and shall make an analysis of the records for the purpose of determining steps to be taken to prevent recurrence of the interruptions. The records shall include the following information concerning the interruptions:

(a) Cause.

(b) Date and time.

(c) Duration.

(3) Planned interruptions shall be made at a time that will not cause unreasonable inconvenience to customers and shall be preceded, if feasible, by adequate notice to persons who will be affected.

(4) Each electric utility or electric cooperative shall promptly notify the commission of any major interruption of service to its customers.

History: 1983 AACS; 1996 AACS.

PART 8. SAFETY

R 460.3801 Protective measures.

Rule 801. Each electric utility or electric cooperative shall exercise reasonable care to reduce the hazards to which its employees, its customers, and the general public may be subjected

History: 1983 AACS.

R 460.3802 Safety program.

Rule 802. Each electric utility or electric cooperative shall comply with the provisions of the occupational safety and health act, 29 U.S.C. S651 et seq., and Act No. 154 of the Public Acts of 1974, as amended, being S408.1001 et seq. of the Michigan Compiled Laws, and known as the Michigan occupational safety and health act, and shall operate under applicable federal and state health and safety laws and regulations.

History: 1983 AACS; 1996 AACS.

R 460.3803 Energizing services.

Rule 803. When energizing services, each electric utility or electric cooperative shall comply with the provisions of all applicable codes and statutory requirements, unless otherwise specified by the commission. The electric utility or electric cooperative may refuse to energize a service if an unsafe condition is observed.

History: 1983 AACS; 1996 AAC.

R 460.3804 Accidents; notice to commission.

Rule 804. Each electric utility or electric cooperative shall promptly notify the commission of fatalities and serious injuries that are substantially related to the facilities or operations of the facilities.

History: 1996 AACS.

R 460.3901 Rescinded.

History: 1983 AACS; 1989 AACS; 1996 AACS.

R 460.3902 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3903 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3904 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3905 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3906 Rescinded.

History: 1983 AACS; 1996 AACS.

R 460.3907 Rescinded.

History: 1996 AACS.

R 460.3908 Rescinded.

History: 1996 AACS.