DEPARTMENT OF STATE

PUBLIC SERVICE COMMISSION

Statutory Authority: 26 Delaware Code, Section 209(a) (26 **Del.C.** §209(a))
26 **DE Admin. Code** 3007

FINAL

ORDER

3007 Electric Service Reliability and Quality Standards

IN THE MATTER OF THE PETITION OF THE PUBLIC SERVICE COMMISSION STAFF AND DELAWARE DIVISION OF THE PUBLIC ADVOCATE TO ESTABLISH A REGULATION FOR DISTRIBUTION SYSTEM INVESTMENT PLANS FOR DELAWARE ELECTRIC AND NATURAL GAS UTILITIES (Filed July 2, 2018)	|	PSC DOCKET NO. 18-0935

ORDER NO. 9541

AND NOW, this 19th day of February 2020, the Public Service Commission ("Commission") determines and orders the following:

WHEREAS, on June 14, 2018, Governor John Carney signed into law Senate Substitute No. 1 for Senate Bill 80, which established a Distribution System Improvement Charge ("DSIC") for electric and natural gas companies in Delaware; and

WHEREAS, on April 14, 2018, the Commission Staff ("Staff"), the Delaware Division of the Public Advocate ("DPA"), and Delmarva Power & Light Company ("Delmarva") executed a Memorandum of Understanding ("MOU") providing that:

> Delmarva Power, the Public Advocate and Commission Staff agree to work together to develop a proposal to submit to the Commission concerning enhanced distribution system planning. Delmarva, DPA and Staff will work in good faith to provide recommendations and to submit any proposals for review and approval to the Commission by September 1, 2019. The first meeting will take place by July 31, 2018. In addition, by no later than March 31, 2019, Delmarva, DPA and Staff will provide the Commission with an update on their progress.

and;

WHEREAS, on May 1, 2018, Chesapeake Utilities Corporation ("Chesapeake") agreed to participate in the meetings among Delmarva, the DPA, and Staff in a good faith effort to recommend to the Commission some form of distribution planning for Chesapeake that will be tied to its DSIC applications; and

WHEREAS, on July 2, 2019, Staff and the DPA jointly filed a petition requesting the Commission to open a docket to examine electric and natural gas utilities' distribution infrastructure spending and establish regulations for distribution system planning to apply to all electric, natural gas, and Class A water utilities; and

WHEREAS, in Order No. 9242 (July 10, 2018), the Commission directed Staff to commence duly-noticed working group meetings for interested stakeholders (including Delmarva and Chesapeake) and to provide recommendations and proposed regulations for the Commission's review and approval; and

WHEREAS, on September 15, 2019, the DPA and Staff presented proposed regulations to the Commission; and

WHEREAS, in Order No. 9485 (Oct. 22, 2019), the Commission authorized publication of the proposed regulations in the December 1, 2019 *Register of Regulations*; and

WHEREAS, the proposed regulations were published in the December 1, 2019 *Register of Regulations*; and

WHEREAS, the Commission received no comments on the proposed regulations; and

WHEREAS, the DPA and Staff request approval of the proposed regulations for final publication with the *Register of Regulations*;

NOW, THEREFORE, BY THE AFFIRMATIVE VOTE OF NO FEWER THAN THREE COMMISSIONERS, IT IS HEREBY ORDERED:

1. The Commission finds and determines that Final Proposed Regulation 3007 attached hereto as "Exhibit A" contains no substantive changes to the Proposed Regulations approved for publication in the Delaware *Register of Regulations* under Commission Order No. 9485 dated October 22, 2019.

2. There is no requirement to re-propose Final Proposed Regulation 3007 because there were no substantive changes; accordingly, the public comment period shall not be extended by 15 days under 29 **Del.C.** § 10118(a) and Final Proposed Regulation 3007 is not subject to the notice requirements of 29 **Del. C.** §10115.

3. Final Proposed Regulation 3007 is hereby approved as final, and the Commission Secretary is directed to publish the Final Proposed Regulation 3007 in the Delaware *Register of Regulations*, with an effective date of not less than 10 days from the date this Order has been published in the *Register of Regulations*.

4. That the Commission reserves the jurisdiction and authority to enter such further orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

Dallas Winslow, Chairman
Joann T. Conaway, Commissioner
Harold B. Gray, Commissioner
Manubhai C. Karia, Commissioner
K. F. Drexler, Commissioner

ATTEST: Donna Nickerson, Secretary

3007 Electric Service Reliability and Quality Standards

EFFECTIVE DATE: September 10, 2006

1.0 Purpose and Scope

1.1 Reliable electric service is an essential service to Delaware citizens of great importance to the Delaware Public Service Commission ("Commission")~~, because it is an essential service to the citizens of Delaware~~. This regulation, in support of 26 **Del.C.**, §1002 and 26 **Del.C.** §1008, sets forth reliability standards, distribution planning requirements, distributed generation considerations, and reporting requirements needed to assure the continued reliability and quality of electric service being delivered to Delaware regulated public utility customers and ~~is applicable~~ applies to all Delaware Electric Distribution Companies ("EDCs") ~~and Delaware Generation Companies~~.

1.2 Nothing in this regulation relieves ~~any utility or generation company~~ an EDC from compliance with any requirement set forth under any other regulation, statute or order. ~~This regulation is in addition to those required under PSC Docket No. 58, Order No. 103, Regulations Governing Service Supplied by Electrical Utilities.~~ To the extent there is any inconsistency between this regulation and any other regulation, or order, this regulation shall control.

1.3 Compliance with this regulation is a minimum standard. Compliance does not create a presumption of safe, adequate and proper service. Each EDC ~~needs to~~ must exercise ~~their~~ its professional judgment based on ~~their~~ its systems and service territories. Nothing in this regulation relieves any ~~utility~~ EDC from the requirement to furnish safe, adequate and proper service and to keep and maintain its property and equipment in such condition as to enable it to do so. (26 **Del.C.**, §209)

1.4 Each EDC ~~shall maintain~~ is responsible for maintaining the reliability of ~~its distribution services and shall implement procedures to require all electric suppliers to deliver energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligations to its customers. (26 **Del.C.**, §1008)~~ electric service to all its customers in the State of Delaware. Pursuant to this requirement, EDCs may be subject to penalties as described in Section 10.0 or 26 **Del.C.** §1019.

1.5 ~~Each generation company operating in the state is required to provide the Commission with an annual assessment of their electric supply reliability as specified in Section 10.~~ EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements.

~~1.6 This regulation requires the maintenance and retention of reliability data and the reporting of reliability objectives, planned actions and projects, programs, load studies and actual resulting performance on an annual basis, including major events as specified in section 11.~~

~~1.7 EDCs are responsible for maintaining the reliability of electric service to all their customers in the state of Delaware. Pursuant to this requirement, EDCs may be subject to penalties as described in Section 13 or 26 **Del.C.**, §1019.~~

~~1.8 EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements.~~

16 DE Reg. 1000 (03/01/13)

2.0 Definitions

The following words and terms, as used in these regulations, shall have the following meanings, unless the context clearly indicates otherwise:

~~**“Acceptable reliability level”** is defined as the maximum acceptable limit of the System Average Interruption Frequency Index (“SAIFI”), the Customer Average Interruption Duration Index (“CAIDI”) and the Forced Outage Rate as specified in Section D.~~

~~**“ALM”** means Active Load Management in accordance with Article 1, Schedule 5.2 of PJM’s Reliability Assurance Agreement (RAA).~~

“Availability” means the measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service.

“Beginning restoration” includes the essential or required analysis of an interruption, the dispatching of an individual or crew to an affected area, and their arrival at the work site to begin the restoration process (normally inclusive of dispatch and response times).

“Benchmark” means the standard service measure of SAIFI, CAIDI and Forced Outage Rate as set forth in these regulations.

“Capacity” means the rated continuous load-carrying ability, expressed in megawatts (“MW”) or megavolt-amperes (“MVA”) of generation, transmission, or other electrical equipment.

~~**“Capacity Emergency Transfer Objective (‘CETO’)”** means the amount of megawatt capacity that an area or sub area must be able to import during localized capacity emergency conditions such that the probability of loss of load due to insufficient tie capability is not greater than one day in 10 years.~~

~~**“Capacity Emergency Transfer Limit (‘CETL’)”** means the amount of megawatts that can actually be imported into the area or sub area during localized capacity emergency conditions.~~

~~**“Constrained hours of operation”** means the hours of electric system operation during which time there are limits, transfer constraints or contingencies on the delivery system that require off-cost dispatch of generating facilities located within the PJM DPL Zone. In measuring compliance to standard, total constrained hours will exclude “major events” and forced generator outages.~~

“Contingency” means the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages.

“Corrective action” means the maintenance, repair, or replacement of an EDC’s utility system components and structures to allow them to function at an acceptable level of reliability.

“Corrective maintenance” means the unplanned maintenance work required to restore delivery facilities to a normal operating condition that allows them to function at an acceptable level of reliability.

“Customer Average Interruption Duration Index (‘CAIDI’)” represents the average time in minutes required to restore service to those customers that experienced sustained interruptions during the reporting period. CAIDI is defined as follows:

$$\textbf{CAIDI} = \frac{\text{Sum of all Sustained Customer Interruption Durations per Reporting Period}}{\text{Total Number of Sustained Customer Interruptions per Reporting Period}}$$

~~**“Customers Experiencing Long Interruption Durations8 ('CELID8')”** represents the total number of customers that have experienced a cumulative total of more than eight hours of outages.~~

~~**“Customers Experiencing Multiple Interruptions8 ('CEMI8')”** is an index that represents the total number of customers that have experienced nine or more interruptions in a single year reporting period.~~

$$\cancel{\textbf{CEMI}_8 = \frac{\text{Total number of customers that experienced more than eight (8) sustained interruptions}}{\text{Total number of customers served}}}$$

“Delivery Facilities” means the EDC’s physical plant used to provide electric energy to Delaware retail customers, normally inclusive of distribution and transmission facilities.

“Dispatch time” is the elapsed time between receipt of a customer call and the dispatch of a service resource to address the customer’s issue as tracked by the OMS.

“Distribution feeder” or “feeder” means a three-phase set of conductors emanating from a substation circuit breaker serving customers in a defined local distribution area. This includes three-phase, two-phase and single-phase branches that are normally isolated at all endpoints.

"Distribution facilities" means electric facilities located in Delaware that are owned by a public utility that operates at voltages of 34,500 volts or below and that are used to deliver electricity to customers, up through and including the point of physical connection with electric facilities owned by the customer.

“Electric Distribution Company” or **“EDC”** means a public utility owning and/or operating transmission and/or distribution facilities in this state.

"Electric distribution system" means that portion of an electric system, that delivers electric energy from transformation points on the transmission system to points of connection at the customers' premises.

"Electric service" means the supply, transmission, and distribution of electric energy as provided by an electric distribution company.

~~**"Electric Supplier"** means a person or entity certified by the Commission that sells electricity to retail electric customers utilizing the transmission and/or distribution facilities of a nonaffiliated electric utility, as further specified in 26 **Del.C.**, §1001.~~

~~**"Forced outage"** means the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure. (See North American Electric Reliability Council - "Glossary of Terms" August 1996.)~~

~~**"Forced outage rate"** means the hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service plus the total number of hours the facility was connected to the electricity system expressed as a percent. (See North American Electric Reliability Council - "Glossary of Terms" August 1996.)~~

> ~~Multiple momentary forced outages on the same transmission line in the span of a single minute shall be treated as a single forced outage with the duration of one minute. When the operation of a transmission circuit is restored following a forced outage and the transmission line remains operational for a period exceeding one minute or more, followed by another forced outage, then these should be counted as two forced outages. Multiple forced outages occurring as a result of a single event should be handled as multiple forced outages only if subsequent operation of the transmission line between events exceeds one minute. Otherwise they shall be considered one continuous forced outage. (See Draft CAISO Transmission Control Agreement, Appendix C, ISO Maintenance Standards.)~~

~~**"Generation company"** means a private or publicly owned company that owns or leases, with right of ownership, plant, equipment and facilities in the state of Delaware, rated in excess of 25 MVA and capable of supplying electric energy to the transmission and/or distribution system.~~

~~**"Generation Working Group"** means a forum within which Generation companies can voluntarily provide to the Commission information related to the operation of their Generating Plants that would otherwise be required pursuant to these Regulations~~

"Interruption" means the loss of electric service to one or more customers. It is the result of one or more component outages, depending on system configuration or other events. See "outage" and "major event." The types of interruption include momentary event, sustained and scheduled.

"Interruption, duration" means the period (measured in minutes) from the initiation of an interruption of electric service to a customer until such service has been restored to that customer. An interruption may require step restoration tracking to provide reliable index calculations.

"Interruption, momentary event" means an interruption of electric service to one or more customers, of which the duration is less than or equal to 5 minutes. This definition includes all reclosing operations, which occur within five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds within five minutes, the event shall be considered one momentary event interruption.

"Interruption, scheduled" means an interruption of electric service that results when one or more components are deliberately taken out of service at a selected time, usually for the purposes of preventative maintenance, repair or construction. Scheduled interruptions, where attempts have been made to notify customers in advance, shall not be included in the SAIFI, CAIDI, or Forced Outage Rate calculations.

"Interruption, sustained" means an interruption of electric service to one or more customers that is not classified as a momentary event interruption and which is longer than five minutes in duration.

"Interrupting device" means a device, capable of being reclosed, whose purpose includes interrupting fault currents, isolating faulted components, disconnecting loads and restoring service. These devices can be manual, automatic, or motor operated. Examples include transmission and distribution breakers, line reclosers, motor operated switches, fuses or other devices.

"Major Event" means an event consistent with the I.E.E.E.1366, Guide For Electric Power Distribution Reliability Indices standard as approved and as may change over time. For purposes of this regulation, changes shall be considered to be in effect beginning January 1 of the first calendar year after the changed standard is adopted by the I.E.E.E. Major event interruptions shall be excluded from the EDC's SAIFI, CAIDI and Forced Outage Rate calculations for comparison to reliability benchmarks. Interruption data for major events shall be collected, and reported according to the reporting requirements ~~outlined in Section 11~~ set forth in this regulation.

~~**"Mid Atlantic Area Council ('MAAC') or Reliability First Corporation"** means a regional council of the North American Electric Reliability Council ("NERC"), or successor organization, that is responsible for Mid~~

~~Atlantic operational policies and reliability planning standards applicable to PJM and local electric distribution company members.~~

~~**"North American Electric Reliability Council ('NERC')"** means the national organization responsible for operational policies and reliability planning standards applicable to national system operations and electric distribution companies, or their successor organizations.~~

"Outage" means the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of electric service to customers, depending on system configuration.

"Outage management system ('OMS')" means a software operating system that provides database information to effectively manage service interruptions and minimize customer outage times.

~~**"Pre-restructuring"** refers to the five-year time frame prior to Delaware's adoption of 26 **Del.C.**, Chapter 10, Electric Utility Restructuring Statute.~~

"PJM Interconnection, L.L.C. ('PJM')" means the independent system operator that is responsible for mid-Atlantic region wholesale energy markets and the interstate transmission of energy, or it's successor organization.

"Power quality" means the characteristics of electric power received by the customer, with the exception of sustained interruptions and momentary event interruptions. Characteristics of electric power that detract from its quality include waveform irregularities and voltage variations – either prolonged or transient. Power quality problems shall include, but are not limited to, disturbances such as high or low voltage, voltage spikes or transients, flicker and voltage sags, surges and short-time overvoltages, as well as harmonics and noise.

"Preventive maintenance" means the planned maintenance, usually performed to preclude forced or unplanned outages, and which allows delivery facilities to continue functioning at an acceptable level of reliability.

"**Related projects**" are individual projects whose completion is required, contingent, or dependent on each other for overall completion of the specified scope of work.

"Reliability" means the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – Adequacy and Security. (See ERC definition - NERC's Reliability Assessment 2001-2010, dated October 16, 2001.)

> **Adequacy** - The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> **Security** - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. (See NERC definition - NERC's Reliability Assessment 2001–2010, dated October 16, 2001.)
>
> As applied to distribution facilities, reliability is further described as the degree to which safe, proper and adequate electric service is supplied to customers without interruption.

"Repair time" is the elapsed time from the arrival of the service resource at the identified problem site to the correction of the customer's original concern as tracked by the OMS.

"Response time" is the elapsed time from dispatch of service resource to the arrival of the service resource at the identified problem site as tracked by the OMS.

"Step restoration" means the restoration of service to blocks of customers in an area until the entire area or circuit is restored.

"Sum of all Sustained Customer Interruption Durations" means the summation of the restoration time (in minutes) for each event times the number of interrupted customers for each step restoration of each interruption event during the reporting period.

"Supervisory Control And Data Acquisition ('SCADA')" is an electronic communication and control system that provides electrical system operating information and mechanisms to remotely control energy flows and equipment.

"System Average Interruption Duration Index ('SAIDI')" represents the average duration of sustained interruptions per customer. SAIDI is defined as:

$$\textbf{SAIDI} = \frac{\text{Sum of all Sustained Customer Interruption Durations per Reporting Period}}{\text{Total Number of Customers Served per Reporting Period}}$$

“System Average Interruption Frequency Index (‘SAIFI’)” represents the average frequency of sustained interruptions per customer during the reporting period. SAIFI is defined as:

$$\textbf{SAIFI} = \frac{\text{Total Number of Sustained Customer Interruptions per Reporting Period}}{\text{Total Number of Customers Served per Reporting Period}}$$

“Total Number of Sustained Customer Interruptions” means the sum of the number of interrupted customers for each interruption event during the reporting period. Customers who experienced multiple interruptions during the reporting period are counted for each interruption event the customer experienced during the reporting period.

“Total Number of Customers Served” means the number of customers provided with electric service by the distribution facility for which a reliability index is being calculated on the last day of the time period for which the reliability index is being calculated. This number should exclude all street lighting (dusk-to-dawn lighting, municipal street lighting, traffic lights) and sales to other electric utilities.

“Transmission facilities” means electric facilities located in Delaware and owned by a public utility that operates at voltages above 34,500 volts and that are used to transmit and deliver electricity to customers (including any customers taking electric service under interruptible rate schedules as of December 31, 1998) up through and including the point of physical connection with electric facilities owned by the customer.

3.0 Electric Service Reliability and Quality

3.1 ~~Each EDC shall provide reliable electric service that is consistent with pre-restructuring service levels as identified in Section 4 and complies with 26 **Del.C.**, §1002.~~ Each EDC shall install, operate and maintain its delivery facilities in conformity with the requirements of the National Electrical Safety Code (“NESC”) and the operating policies and standards of NERC and PJM, or their successor organizations.

3.2 ~~Each EDC shall install, operate, and maintain its delivery facilities in conformity with the requirements of the National Electrical Safety Code and the operating policies and standards of NERC, MAAC and PJM, or their successor organizations.~~ Each EDC shall ensure that distribution, system generation interconnection requirements are consistent with the I.E.E.E. 1547 series, “Standard for Interconnecting Distributed Resources with Electric Power Systems,” as current approved and may be revised.

~~3.3~~ ~~Each EDC shall have targeted objectives, programs and/or procedures and forecast load studies, designed to help maintain the acceptable reliability level for its delivery facilities and, where appropriate, to improve performance.~~

~~3.4~~ ~~Each EDC, in accordance with Section 9, shall submit to the Commission, on or before March 31 of each year, a Planning and Studies Report identifying its current year’s annual objectives, planned actions and projects, programs, and forecast studies that serve to maintain reliability and quality of service at an acceptable reliability level.~~

~~3.5~~ ~~Each EDC, in accordance with Section 10, shall submit to the Commission, on or before April 30 of each year, a Performance Report that assesses the achievement of the previous year’s objectives, planned actions, projects and programs, and assesses the relative accuracy of forecast studies and previous years performance measures with respect to benchmarks.~~

~~3.6~~ ~~Each generation company in accordance with Section 10. shall submit to the Commission on or before April 30 of each year, a Performance Report that evaluates their reliability of energy supply.~~

~~3.7~~ ~~Each EDC shall ensure that distribution system generation interconnection requirements are consistent with the I.E.E.E. 1547 series, "Standard for Interconnecting Distributed Resources with Electric Power Systems, as currently approved and as may be revised.~~

~~3.8~~ ~~Each EDC shall file and maintain with the Commission a copy of the technical requirements for distribution system generation interconnection.~~

4.0 Reliability and Quality Performance Benchmarks

4.1 The measurement of reliability and quality performance shall be based on annual SAIDI and ~~Constrained Hours of Operation measures for each EDC~~ SAIFI calculations. The SAIDI ~~calculation~~ and SAIFI calculations shall ~~include all Delaware customer outages, excluding major events, and shall be reported along with its SAIFI and CAIDI components, subdivided by its distribution, substation and transmission components. The Constrained Hours of Operations shall be based on peninsula (DPL Zone) transmission system contingency limitations that require the dispatch of off-cost generation, excluding generation or transmission forced outages, generation or transmission related construction or any unrelated third party actions~~ be derived using the most current IEEE 1366 Beta methodology. The SAIDI and SAIFI calculations shall include all Delaware customer outages, excluding scheduled interruptions, and major events, and the SAIDI and SAIFI calculations shall be reported along with their CAIDI component, subdivided by their distribution, substation, and transmission components.

4.2 Each EDC shall take measures to maintain ~~their~~ its overall electric service reliability and quality performance measures within the benchmark standard ~~of this Section 4, Paragraph 4.3. SAIDI and Constrained Hours of Operation performance shall be measured each calendar year. Annual SAIDI and Hours of Constrained Operation performance equal to or better than the acceptable reliability level meets the standard of this regulation. When performance does not meet the acceptable reliability level, further review and analysis are required. The EDC may be subject to penalties as defined in Section 13. and subsequent corrective actions may be required.~~ as follows:

4.2.1 The three-year average SAIFI shall not exceed 1.0 interruption.

4.2.2 The three-year average SAIDI shall not exceed 100 minutes.

4.3 ~~For the EDCs, the electric service reliability and quality performance benchmarks are established as follows:~~ Every three years, the SAIDI and SAIFI benchmarks will be reset by the same percentage that the respective three-year IEEE threshold between first and second quartile has changed.

~~4.3.1 The system SAIDI benchmark standard, which is based on pre-restructuring levels of performance and adjusted to reflect a 1.75 standard deviation of data variability and the transition to an OMS system shall be as follows:~~

~~4.3.1.1 Delaware Electric Cooperative SAIDI shall be 635 minutes per customer; and~~

~~4.3.1.2 Delmarva Power SAIDI shall be 295 minutes per customer.~~

~~4.3.2 Based on the PEPCO/Conectiv merger settlement, the Constrained Hours of Operation benchmark standard shall be 600 hours for each EDC.~~

4.4 ~~Each EDC shall track and report its annual performance and three-year average performance against benchmark standards in accordance with Section 10.~~ Each EDS shall develop and maintain a comprehensive Priority Feeder program for analyzing the reliability performance of its circuits during the course of each year which includes methods to measure and improve works performing circuits.

4.5 ~~Each EDC shall track and report its annual CAIDI, SAIFI, CEMI8 and CELID8 performance in accordance with Section 10.~~ When performance does not meet the acceptable reliability level, additional monitoring and enforcement actions may be taken including the following: additional remedial review, requiring additional EDC reporting, conducting an informal investigation, initiating a formal complaint, requiring a formal improvement plan with enforceable commitments, requiring an implementation schedule, and assessing penalties and fines as defined in Section 10.0.

5.0 Reliability and Quality Performance Objectives

~~5.1 Each EDC shall establish electric service reliability and quality performance objectives for the forthcoming year. Objectives shall include:~~

~~5.1.1 Anticipated performance measures designed to maintain reliable electric distribution service with a description of any planned actions to achieve target objectives;~~

~~5.1.2 Anticipated performance measures designed to maintain transmission circuits and power transformers with a description of any planned actions to achieve target objectives; and~~

~~5.1.3 Annual corrective and preventive maintenance program hours anticipated on Delaware transmission circuits, distribution circuits and substation equipment.~~

~~5.2 Performance objective measures shall be established to support the maintenance of electric reliability performance. Performance objectives shall be representative of expected performance, taking into consideration anticipated new construction projects, quality and maintenance programs, planned actions and any resource or time limitations.~~

5.1 Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities performance at an acceptable level. The program shall be based on industry codes, national electric industry practices, manufacturer's recommendations, sound engineering judgement, NESC Rule 214 guidance, and past experience.

5.2 As a maintenance minimum, each EDC shall inspect all right-of-way vegetation at least once every four (4) years and trim or maintain as necessary, according priority to circuits that have had significant numbers of vegetation-related outages, while not unduly delaying the trimming of other circuits that inspections indicate currently need trimming. Vegetation management practices should be applied at least once every four (4) years except where growth or other assessments deem it unnecessary.

5.3 Each EDC shall maintain records of inspection and maintenance activities. Compliance with this requirement may be established by showing of substantial compliance without regard for a single particular facility maintenance record. These records shall be made available to the Delaware Public Service Commission Staff ("Staff") and the Division of the Public Advocate ("DPA") upon request of either party with 30 days' notice.

~~**6.0 Power Quality Program**~~

~~6.1 Each EDC shall maintain a power quality program with clearly stated objectives and procedures designed to respond promptly to customer reports of power quality concerns.~~

~~6.2 Each EDC shall consider power quality concerns in the design, construction and maintenance of its transmission and distribution power delivery system components to mitigate, using reasonable measures, power quality disturbances that adversely affect customers' equipment.~~

~~6.3 Each EDC shall maintain records of customer power quality concerns and EDC response. These records shall be made available to the Commission Staff upon request with 30 days notice.~~

6.0 Distribution Planning and Studies Report

6.1 Long Range Distribution Plan

6.1.1 As the entity responsible for the planning of its system, each EDC shall submit a Long Range Distribution Plan ("LRDP") to identify existing and potential future distribution system performance issues, and recommended solutions, for a minimum of ten (10) years to be refreshed every five (5) years. This plan is intended to serve as the strategic direction for an EDC's anticipated major initiatives. The LRDP shall be submitted, subject to subsection 6.3, by June 15th every fifth year. The first LRDP shall be submitted by June 15, 2022, for the effective period of 2023-2032.

6.1.2 The LRDP shall include:

6.1.2.1 An updated analysis populated with current and projected loads for the term of the LRDP, trending tables, set of limiting factors, and other criteria used to establish a project need.

6.1.2.2 A system evaluation of equipment and circuit loading compared to thermal limits, breaker operating capability, asset condition, and safety and environmental issues. Contingency (N-1) response capability will be analyzed at the substation level, and as appropriate, at the feeder level.

6.1.2.3 The specific programs and / or projects included in the LRDP will be longer-term initiatives that require multiple years from concept through implementation. The LRDP will include recommendations that provide a comprehensive solution to address projected system performance concerns. All proposed projects within the LRDP shall be supported by:

6.1.2.3.1 A detailed description of the system condition, recommended solutions, and anticipated timing of solution implementation;

6.1.2.3.2 A detailed comparison of recommended solutions to alternatives, including implementation of utility or third-party owned non-wires alternatives (NWA) as appropriate, in a manner that clearly identifies the reliable, and environmentally responsible investment; and

6.1.2.3.3 Current cost estimates, which may be at a budgetary level.

6.1.2.4 System capacity and voltage driven projects identified within the first five (5) years of the LRDP shall include a system engineering model covering the affected and adjoining areas that may be impacted by the proposed project.

6.1.2.5 Non-wires alternatives in whole, or in part, shall be considered as solutions to capacity and/or major asset condition related system performance issues. A project whose estimated cost exceeds $1,000,000 over the term of the LRDP shall be evaluated for a NWA.

6.2 Infrastructure, Safety and Reliability Plan

6.2.1 The EDC shall submit a proposed rolling 3-year Infrastructure, Safety, and Reliability Plan ("ISR") identifying proposed capital spending necessary to maintain the reliability and quality of its distribution services. Subject to subsection 6.3, the proposed ISR shall be submitted no later than March 31, 2020 or 90 days following the effective date of this regulation, whichever is later, and no later than March 31st every year thereafter. The initial report shall address 2020-2022, and subsequent reports will address the year in which it is submitted and two subsequent years. The proposed ISR shall be structured under the following major spending categories:

6.2.1.1 Mandatory

6.2.1.1.1 New business - Customer Requirements

6.2.1.1.2 Facility relocations

6.2.1.1.3 Required Statutory and Regulatory Requirements

6.2.1.1.4 Reliability – emergency failures

6.2.1.2 Non-Mandatory

6.2.1.2.1 System Capacity/Load

6.2.1.2.2 Asset Condition

6.2.1.2.3 Other Reliability

6.2.1.3 Vegetation Management

6.2.1.4 Inspection and Maintenance ("I&M") program

6.2.2 Mandatory spending shall include investments required to comply with customer requests, facility relocations, statutory and regulatory requirements, and to fix failed equipment. The proposed budgets may be for a combination of discrete projects and projects that are funded but whose specific scope has not yet been defined ("blanket projects").

6.2.3 Non-Mandatory spending shall include those projects, programs, or other investments, including NWAs, necessary to maintain or improve distribution services and not included in the Mandatory spending category. Projects or groups of related projects shall be supported with project authorization documents including detailed cost estimates. I&M and reliability-based programs shall be supported by guidelines or program documents. The proposed budgets may be for a combination of discrete projects and blanket projects.

6.2.4 To support each proposed annual budget, the proposed ISR shall describe: how the EDC developed the spending plan and levels; reference of applicable proposed projects to the LRDP, the justification, scope, and estimated cost, for each planned project of $1,000,000 or more; planned I&M activities and expected improvements; other planned reliability or maintenance programs; and planned vegetation management targets and activities.

6.2.5 The proposed ISR shall include the EDC's estimated cost of plant in service and cost of removal for each year of the three-year term.

6.2.6 For major projects or groups of related projects in the System Capacity/Load or Asset Condition categories that exceed $1,000,000 over the term of the ISR and were not included in the LRDP, the ISR will include the information required in subsections 6.1.2.3 and 6.1.2.4.

6.3 Review and Acknowledgement

6.3.1 Each LRDP or ISR ("Plan") shall be submitted to the Staff and the DPA. Within the first 90 days following submission of each Plan, the EDC, Staff, and the DPA shall cooperate in good faith and schedule, if necessary, at least two sessions to meet and confer on the proposed Plan and discuss any proposed modifications.

6.3.2 No later than 120 days following the EDC's submission of each Plan to Staff and the DPA, the EDC shall file the proposed Plan with the Commission.

6.3.3 Staff and the DPA may submit comments to the Plan by filing those comments to the Commission within ten days of the EDC's filing of its proposed Plan.

6.3.4 The EDC has the right to file reply comments to Staff and the DPA comments within ten days of their filings to the proposed Plan.

6.3.5 The Commission shall acknowledge that the Plan and any associated comments has been filed and is consistent with the requirements of this regulation. Commission acknowledgement shall not constitute Commission pre-approval of any proposed capital spending necessary to maintain the reliability and quality of the EDC's distribution services.

6.3.6 Any party may challenge the EDC's attempt to recover the amounts spent.

6.3.7 The EDC's obligation to maintain reliability and quality of its distribution system may necessitate executing on the plan prior to the PSC's acknowledgement In executing the ISR Plan, the circumstances encountered during the year may require reasonable deviations from the filed ISR Plan.

~~7.0 Inspection and Maintenance Program~~

~~7.1 Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities performance at an acceptable reliability level. The program shall be based on industry codes, national electric industry practices, manufacturer's recommendations, sound engineering judgment and past experience.~~

~~7.2 As a maintenance minimum, each EDC shall inspect and maintain as necessary its power transformers, circuit breakers, substation capacitor banks, automatic 3-phase circuit switches and all 600 amp or larger manually operated, gang transmission circuit tie switches at least once every two (2) years.~~

~~7.3 As a maintenance minimum, each EDC shall inspect all right-of-way vegetation at least once every four (4) years and trim or maintain as necessary, according priorities to circuits that have had significant numbers of vegetation-related outages, while not unduly delaying the trimming of other circuits that inspections indicate~~

~~currently need trimming. Vegetation management practices should be applied at least once every four (4) years except where growth or other assessments deem it unnecessary.~~

~~7.4 Each EDC shall maintain records of inspection and maintenance activities. Compliance with this requirement may be established by a showing of substantial compliance without regard for a single particular facility maintenance record. These records shall be made available to Commission Staff upon request with 30 days notice.~~

7.0 Annual Reports

7.1 Reliability Performance

7.1.1 By April 30 of each year, each EDC shall file with the Commission an annual Reliability Performance Report ("RPR") providing an overall assessment of the state of system reliability in the EDC's service territory. The RPR shall include an assessment of the results/effectiveness of reliability objectives, planned actions, projects, and programs implemented to achieve an acceptable reliability level. The RPR shall include the EDC's actual year-end performance measure results.

7.1.2 The RPR shall include the EDC's delivery facilities' year-end performance measures as follows:

7.1.2.1 SAIDI, SAIFI, and CAIDI measures:

7.1.2.1.1 SAIDI, SAIFI, and CAIDI measures for the current year and three-year average reflecting Delaware performance, classified by distribution and substation components and in total, as compared to the benchmarks established in subsection 4.2;

7.1.2.1.2 SAIDI, SAIFI, and CAIDI measures for the current and previous five (5) years compared to IEEE regional results, indicating the quartile achieved; and

7.1.2.1.3 CAIDI measures for the current year and three-year average for each circuit providing service to Delaware customers, regardless of state of origin.

7.1.3 The RPR shall identify distribution circuits that are identified by the EDC as having the poorest reliability according to the criteria in the EDC's Priority Feeder Program.

7.1.3.1 Current and previous five (5) year summary level OMS data to include:

7.1.3.1.1 Number of outages by outage type;

7.1.3.1.2 Number of outages by outage cause;

7.1.3.1.3 Total number of customers at year end;

7.1.3.1.4 Total number of customers that experienced an outage; and

7.1.3.1.5 Total customer minutes of outage time.

7.1.3.2 The EDC shall indicate any planned corrective actions to improve circuit performance and target dates for completion or explain why no action is required.

7.1.4 The RPR shall include a summary of each major event for which data was excluded, and an assessment of the measurable impact on reported performance measures.

7.1.5 In the event that an EDC's reliability performance measure does not meet the performance measures established in subsection 4.2, the RPR shall include a description of system issues impacting reliability and all corrective actions that are planned by the EDC; the estimated cost of corrective actions; and the target dates by which the corrective actions shall be completed. If no corrective actions are planned, an explanation shall be provided.

7.2 Infrastructure, Safety, and Reliability Plan Annual Report

7.2.1 By March 31st of each year, starting March 31, 2021, each EDC shall submit an ISR annual report for the previous year to include:

7.2.1.1 Overall progress.

7.2.1.2 Budget to actual variance for each spending category (both plant in service/COR and spending plan) with discussion of drivers.

7.2.1.3 Comparison of actual versus planned project implementation with discussion of deviations including delays and accelerated work; and, explanation for inclusion of any program, project, or group of related projects with a total cost estimate exceeding $1,000,000 that were not previously included in an ISR.

7.2.1.4 Comparison of I&M and vegetation management program activities to plan, with discussion of deviations and drivers.

7.2.1.5 Comparison of any other projects or programs.

7.2.1.6 An explanation of the variance for any program and/or project exceeding $1,000,000 that was completed in the reporting year and exceeds +/- 10% of the proposed budget.

~~**8.0 Delivery Facility Studies**~~

~~8.1 Each EDC shall perform system load studies to identify and examine potential distribution circuit overloads, distribution substation and distribution substation supply circuit single contingencies and all transmission system single and double contingencies as specified by NERC, MAAC, Reliability First Corp. and PJM or successor requirements. Double contingency analysis should include supply service contingencies that may cause overloads or outages on the EDC's system. Where NERC, MAAC, Reliability First Corp or PJM requirements are not applicable, the EDC shall at a minimum examine circuit and equipment overloads under normal and single contingency conditions at peak load, with and without ALM or other demand response mechanisms. The EDC shall identify all projects and/or corrective actions that are planned to mitigate reliability loading issues identified in the study.~~

~~8.2 Delivery facility planning studies will be performed annually under conditions specified by NERC, MAAC, Reliability First Corp. and PJM or their successor organization's planning requirements, or as specified in 8.1. Studies shall identify required projects and/or planned corrective actions. For any study resulting in a thermal overload or an out-of-range voltage level, the study shall be performed again after the implementation of Active Load Management (ALM), system switching or reconfiguration.~~

~~8.3 Each EDC shall perform the electric delivery facility system planning studies as described herein in the fall of each year (year a) for the upcoming summer period (year b) and for the summer period two years later (year c). The planning studies will include all delivery facility enhancements planned to be in-service during the applicable summer peak and shall identify those delivery facilities that are anticipated to be overloaded during the peak demand period.~~

8.0 Major Event Report

8.1 Each EDC shall notify the Commission of major events as soon as practical, but not more than 36 hours after the onset of a major event. Initial notification is required when more than 10% of an EDC's customers experience a sustained outage during a 24- hour period, calculated according to I.E.E.E. 1366 standards.

8.2 Each EDC is expected to restore service to customers as quickly and safely as permitted by major event conditions. The EDC's restoration effort may be subject to review, subsequent corrective actions and penalties as permitted by 26 **Del.C.** §1019.

8.3 The EDC shall, within 15 business days after the end of a major event, submit a written report to the Commission, which shall include the following:

8.3.1 The date and time when the EDC's major event control center opened and closed;

8.3.2 The total number of customers' out-of-service over the course of the major event in six-hour increments;

8.3.3 The date and time when 75%, 95% and 100% of customers affected by a major event were restored;

8.3.4 The total number of trouble assignments repaired, by facility classification (poles, miles of wire, transformers);

8.3.5 The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance; and

8.3.6 A timeline profile in six-hour increments of the number of company line crews, mutual aid crews, and non-company contractor line and tree crews working on restoration activities during the duration of the major event, summarized by total number of line, bucket, trouble, and tree types.

~~**9.0 Planning and Studies Report**~~

~~9.1 Prior to May 31 of each year, each EDC shall convene a stakeholder meeting offering opportunity for interested parties to discuss electric service reliability or quality concerns within Delaware. Such meeting shall be limited to discussion of publicly available information and at a minimum be open to generation companies, electric suppliers, municipals or other EDCs, PJM, state agencies and wholesale/retail consumers. Each EDC shall consider the resulting issues and include mitigation efforts in annual plans as appropriate.~~

~~9.2 By March 31 of each year, each EDC shall submit a reliability planning and studies report to the Commission for review. The report will identify current reliability objectives, load study results and planned actions, projects or programs designed to maintain the electric service reliability and quality of the delivery facilities.~~

~~9.3 The report shall include the following information:~~

~~9.3.1 Objective targets or goals in support of reliable electric service and descriptions of planned actions to achieve the objectives;~~

~~9.3.2 Delivery load study results as described in Section 8., to include at a minimum the information for both year b and year c as specified in Section 8., Paragraph 8.3.;~~

~~9.3.3 Description and estimated cost of capital projects planned to mitigate loading or contingent conditions identified in load studies or required to manage hours of congestion;~~

~~9.3.4 The EDC's power quality program and any amendments as required in Section 6.;~~

~~9.3.5 The EDC's inspection and maintenance program, any amendments as required in Section 7., and any specific actions aimed at reducing outage causes;~~

~~9.3.6 Copies of all recent delivery facility planning studies and network capability studies (including CETO and CETL results) performed for any delivery facilities owned by the utility; and~~

~~9.3.7 Summaries of any changes to reliability related requirements, standards and procedures at PJM, MAAC, First Reliability Corporation, NERC or the EDC.~~

~~9.3.8 Summary of any issues that resulted from the EDC stakeholder meeting and any projects or planning changes that may have been incorporated as a result of such meeting.~~

9.0 Guidelines, Standards and Programs

9.1 The EDC shall file with the Commission the most current version of the following guidelines, standards, and programs:

9.1.1 Distribution System Planning Criteria;

9.1.2 Inspection and Maintenance Program;

9.1.3 Vegetation Management Program;

9.1.4 Standard for Interconnecting Distributed Resources with Electric Power Systems;

9.1.5 Power Quality Program and Policies;

9.1.6 Priority Feeder Program; and

9.1.7 Storm Response Plan.

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~~**10.0 Annual Performance Report**~~

~~10.1 By April 30 of each year, each EDC shall submit an annual Performance Report, summarizing the actual electric service reliability results. The report shall include the EDC's average three-year performance results, actual year-end performance measure results and an assessment of the results/effectiveness of the reliability objectives, planned actions and projects, programs, and load studies in achieving an acceptable reliability level.~~

~~10.2 Delivery facilities year-end performance measures, as established in Section 4., Paragraph 4.1 shall be reported as follows:~~

~~10.2.1 SAIDI, SAIFI, and CAIDI measures:~~

~~10.2.1.1 Current year and three-year average reflecting Delaware performance, classified by distribution, substation and transmission components; and~~

~~10.2.1.2 Current year for each feeder circuit providing service to Delaware customers, regardless of state origin.~~

~~10.2.2 Constrained hours of operation:~~

~~10.2.2.1 Current year and three-year average for the EDC's DPL Zone transmission system; and~~

~~10.2.2.2 Current year for the EDC's DPL Zone, classified by cause.~~

~~10.3 The Performance Report shall identify 2% of distribution feeders or 10 feeders, whichever is more, serving at least one Delaware customer, that are identified by the utility as having the poorest reliability. The EDC shall identify the method used to determine the feeders with poorest reliability and shall indicate any planned corrective actions to improve feeder performance and target dates for completion or explain why no action is required. The EDC shall ensure that feeders, identified as having the poorest reliability, shall not appear in any two consecutive Performance Reports without initiated corrective action.~~

~~10.4 The Performance Report shall include annual information that provides the Commission with the ability to assess the EDC's efforts to maintain reliable electric service to all customers in the state of Delaware. Such reporting shall include the following items:~~

~~10.4.1 Current year expenditures, labor resource hours, and progress measures for each capital and/or maintenance program designed to support the maintenance of reliable electric service, to include:~~

~~10.4.1.1 Transmission vegetation maintenance;~~

~~10.4.1.2 Transmission maintenance, excluding vegetation, by total, preventive, and corrective categories;~~

~~10.4.1.3 Transmission capital infrastructure improvements;~~

~~10.4.1.4 Distribution vegetation maintenance;~~

~~10.4.1.5 Distribution maintenance, excluding vegetation, by total, preventive and corrective categories;~~

~~10.4.1.6 Distribution capital infrastructure improvements;~~

~~10.4.1.7 Transmission and Distribution progress per Section 7, Paragraphs 7.2 and 7.3; and~~

~~10.4.1.8 Any related process, practice or material improvements.~~

~~10.4.2 Current year OMS data to include:~~

~~10.4.2.1 Number of outages by outage type;~~

~~10.4.2.2 Number of outages by outage cause;~~

~~10.4.2.3 Total number of customers at year end;~~

~~10.4.2.4 Total number of customers that experienced an outage; and~~

~~10.4.2.5 Total customer minutes of outage time.~~

~~10.4.3 Current year CELID8 and CEMI8 results, exclusive of major events, including any efforts being made to reduce the occurrences of multiple outages or long duration outages.~~

~~10.4.4 Current year customer satisfaction or other measures the EDC believes are indicative of reliability performance.~~

~~10.5 The Performance Report shall include a summary of each major event for which data was excluded, and an assessment of the measurable impact on reported performance measures.~~

~~10.6 In the event that an EDC's reliability performance measure does not meet an acceptable reliability level for the calendar year, the Performance Report shall include the following:~~

~~10.6.1 For not meeting SAIDI, an analysis of the customer service interruption causes for all delivery facilities by dispatch, response and repair times that significantly contributed to not meeting the benchmark;~~

~~10.6.2 For not meeting Constrained Hours of Operation, an analysis of significant constraints by cause;~~

~~10.6.3 A description of any corrective actions that are planned by the EDC and the target dates by which the corrective action shall be completed; and~~

~~10.6.4 If no corrective actions are planned, an explanation shall be provided.~~

~~10.7 The Performance Report shall include copies of current procedures identifying methods the EDC uses to ensure the electric supplier delivery of energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligation to its customers.~~

~~10.8 The Performance Report shall include certification by an officer of the EDC of the data and analysis and that necessary projects, maintenance programs and other actions are being performed and adequately funded by the Company as addressed in its annual plans.~~

~~10.9 Unless a generation company participates in the Generation Working Group, each generation company shall submit by April 30 of each year an annual Reliability Performance Report. The performance report shall include the individual unit and average station forced outage rates and any anticipated changes that may impact the future adequacy of supply. Each generation company shall also provide the Commission with at least a one-year advanced notification of any planned unit retirements, planned re-powerings or planned long-term unit de-ratings.~~

~~10.9.1 The performance report required by Section 10.9 shall include the individual unit and average station forced outage rates and any anticipated changes that may impact the future adequacy of supply.~~

~~10.9.2 Each generation company not a member of a Generation Working Group shall also provide the Commission with at least a one-year advanced notification of any planned unit retirements, planned re-powerings or planned long-term unit de-ratings.~~

~~10.10 In lieu of submission of an annual Reliability Performance and one-year advanced notification, as required in Section 10.9, Generation companies may voluntarily participate in a Generation Working Group.~~

~~10.10.1 The Commission shall designate one member of the Commission Staff to chair the Working Group. Such individual shall be referred to as the "Commission Staff Member."~~

~~10.10.2 Meetings of the Generation Working Group shall be no less frequently than semi-annually, and shall be scheduled by the Commission Staff Member.~~

~~10.10.3 The purpose of the semi-annual meetings will be for the Commission Staff Member and the participating Generation company or companies, as the case may be, to agree upon the specific parameters of generation information to be provided by member Generation companies to the Commission and how and when such information should be presented to the Commission. The specific parameters and presentation of information need not be identical for Generation Company, as agreed by the Generation Working Group.~~

~~10.10.4 In the event of a disagreement between the Commission Staff Member and a Generation company, the Generation Working Group will attempt to resolve the disagreement by consensus. If consensus cannot be achieved in a reasonable time, the Generation Working Group or any member may request a determination by the Commission of the issue.~~

~~10.10.5 To allow Generation companies to participate openly without disclosing commercially-sensitive information to each other, the semi-annual Working Group meetings may be supplemented with meetings between the Commission Staff Member and individual Generation companies. Such individual meetings may be requested, on an as needed basis, by the Commission Staff Member or by a Generation company.~~

~~10.10.6 The Generation company or companies, as the case may be, shall use its or their best efforts to provide the requested information within an agreed-upon period of time.~~

~~10.10.7 The Commission and each member of the Generation Working Group shall implement all steps necessary to protect the confidentiality of commercially sensitive information provided by the Generation company or companies, as the case may be.~~

~~10.10.8 Each member of the Generation Working Group reserves the right to not provide information of a commercially-sensitive nature to all or some of the members of the Generation Working Group unless and until it obtains legally sufficient protection against non-disclosure of such information, and each such member shall take reasonable steps to procure such legally sufficient protection, to the extent these Rules do not constitute such protection.~~

~~10.10.9 Any Generation company participating in the Generation Working Group may withdraw at any time.~~

10.0 Penalties and Other Remedies

10.1 EDCs operating in Delaware and subject to Commission regulation who violate any of the requirements of this regulation are subject to penalties and other remedial actions in accordance with 26 **Del.C.** §§205(a), 217, and 1019. No penalty shall be assessed except after a public hearing at which the EDC, Staff, the DPA, or any other affected person may present evidence. The Commission shall be responsible for assessing any penalty under this section, consistent with Delaware law.

10.2 An EDC shall be considered in violation of the SAIDI or SAIFI performance benchmark standard when its actual results exceed the benchmark standard(s) as defined in subsection 4.2.

10.3 Penalty assessments are payable as provided by Delaware statute.

10.4 Nothing in this section relieves any EDC from compliance or penalties that may be assessed due to non-compliance with any requirement set forth under any other regulation, statute or order.

~~**11.0 Major Event Report**~~

~~11. 1 Each EDC shall notify the Commission of major events as soon as practical, but not more than 36 hours after the onset of a major event. Initial notification is required when more than 10% of an EDC's customers experience a sustained outage during a 24 hour period; however, I.E.E.E. 1366 standard shall apply to all performance calculations.~~

~~11.2 Each EDC is expected to restore service to customers as quickly and safely as permitted by major event conditions. The EDC's restoration effort may be subject to review, subsequent corrective actions and penalties as permitted by 26 **Del.C.** §1019.~~

~~11.3 The EDC shall, within 15 business days after the end of a major event, submit a written report to the Commission, which shall include the following:~~

~~11.3.1 The date and time when the EDC's major event control center opened and closed;~~

~~11.3.2 The total number of customers out-of-service over the course of the major event in six hour increments;~~

~~11.3.3 The date and time when 75%, 95% and 100% of customers affected by a major event were restored;~~

~~11.3.4 The total number of trouble assignments repaired, by facility classification (poles, miles of wire, transformers);~~

~~11.3.5 The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance; and~~

~~11.3.6 A timeline profile in six-hour increments of the number of company line crews, mutual aid crews, non-company contractor line and tree crews working on restoration activities during the duration of the major event, summarized by total number of line, bucket, trouble, and tree types.~~

11.0 Reporting Specifications and Implementation

11.1 Each EDC must maintain sufficient records to permit a review and confirmation of material contained in all required planning documents and reports. Reports shall be submitted electronically via Delafile to the

Secretary, Delaware Public Service Commission, with certification of authenticity by an officer of the corporation.

11.2 Subject to and without waiving the requirements of 29 **Del.C.** Ch. 100 (the “Freedom of Information Act” or “FOIA”), EDCs may request information required under this regulation to be classified as confidential, proprietary and/or privileged material. The requesting party must attest that such information is not subject to inspection by the public or other parties without execution of an appropriate proprietary agreement. Each party requesting such treatment of information is also obligated to file one (1) additional electronic and paper copy of the information, excluding the confidential or proprietary information. The Commission, in accordance with the FOIA and 26 **DE Admin. Code** 1001, will treat such information as "confidential, not for public release" upon receipt of a properly filed request. The Commission, designated Presiding Officer, or Hearing Examiner shall resolve any dispute over the confidential treatment of information in accordance with the FOIA and 26 **DE Admin. Code** 1001.

~~**12.0 Prompt Restoration of Outages**~~

~~12.1 Each EDC shall strive to restore service as quickly and as safely as possible at all times EDCs shall begin the restoration of service to an affected service area within two hours of notification by two or more customers of any loss of electric service. In situations where it is not practical to respond within two hours to a reported interruption (safety reasons, inaccessibility, multiple simultaneous interruptions, storms or other system emergencies), the EDC shall respond as soon as the situation permits.~~

~~12.2 Each EDC shall monitor dispatch, response and repair times for customer outages. In the event that average annual dispatch, response or repair performance times exceed the EDC's expected levels for the calendar year, the EDC shall include the following in its annual performance report.~~

~~12.2.1 An analysis of the factors which caused the unexpected performance; and~~

~~12.2.2 A description of any corrective actions planned by the EDC to meet expected performance levels.~~

~~12.3 Each EDC shall have outage response procedures that place the highest priority on responding to emergency situations for which prompt restoration is essential to public safety. These procedures should include recognition of priority requests that may come from police, fire, rescue, authorized emergency service providers or public facility operators.~~

~~**13.0 Penalties and Other Remedies**~~

~~13.1 Private or investor owned utilities and cooperatives, operating in Delaware under the regulation of the Commission, are subject to penalties and other remedial actions in accordance with 26 **Del.C.**, §205(a), §217, and §1019. The Commission shall be responsible for assessing any penalty under this section, consistent with Delaware law. In determining if there should be a penalty for violation of a reporting requirement or benchmark standard and, if so, what the penalty amount should be, the Commission shall consider the nature, circumstances, extent and gravity of the violation including the degree of the EDC's culpability and history of prior violations and any good faith effort on the part of the EDC in attempting to achieve compliance. Such penalty shall not exceed $5,000 for each violation, with the overall penalty not to exceed an amount reasonable and appropriate for the violation (maximum of $600,000 per year per reporting or standard violation). Each day of noncompliance shall be treated as a separate violation. In the case of an electric cooperative, in violation of a reporting requirement or benchmark standard, the Commission shall not assess any monetary penalty that would adversely impact the financial stability of such an entity and any monetary penalty that is assessed against an electric cooperative shall not exceed $1,000 for each violation, which each day of noncompliance shall be treated as a separate violation (maximum of $60,000 per year per reporting or standard violation). Nothing in this section relieves any private or investor owned utility or cooperative from compliance or penalties, that may be assessed due to non-compliance with any requirement set forth under any other regulation, statute or order.~~

~~13.2 An EDC shall be considered in violation of the SAIDI or Constrained Hours of Operation performance benchmark standard when the annual year-end cumulative measure exceeds the benchmark standard. The term of the violation shall extend for the period of time during which the performance measure exceeded the benchmark standard.~~

~~13.3 Upon failure of any EDC to meet performance benchmark standards, the EDC shall report monthly, or over such other period of time that the Commission shall establish by order, the latest performance indices, until such time as performance meets the acceptable reliability level.~~

~~13.4 Each EDC not meeting performance benchmark standards as required by Section 4, shall inform its customers, in writing, of the results and plans to improve electric service reliability and quality by July 1 of the year following any year in which its performance does not meet an acceptable reliability level.~~

~~13.5 Each violation of any reporting rule or performance standard of this regulation shall constitute a single, separate and distinct violation for that particular day. Each day during which a violation continues shall constitute an additional, separate and distinct violation. Provided, however, that a violation of a performance measure shall not be deemed to be a violation per customer, whether affected or otherwise, but shall constitute a single Delaware-wide violation for the day.~~

~~13.6 In a proceeding to determine penalties or other remedial measures for any violation, but particularly with respect to the Constrained Hours of Operation, the Commission should consider the extent to which the measure or reporting requirement did not meet the established standard and the extent to which the EDC may have implemented cost-effective efforts to comply with the requirement.~~

~~13.7 Penalty assessments are payable as provided by Delaware statute.~~

~~14.0 Outage Management System (OMS)~~

~~14.1 Each EDC shall implement and maintain an Outage Management System (OMS) and a Supervisory Control and Data Acquisition System (SCADA) as described in this section by January 1, 2007.~~

~~14.2 The OMS, at a minimum, shall consist of an outage assessment software program, integrated with a geographic information system that permits an EDC to effectively manage outage events and restore customer service in a timely manner.~~

~~14.3 The OMS should permit the EDC to:~~

~~14.3.1 Group customers who are out of service to the most probable interrupting device that operated;~~

~~14.3.2 Associate customers with distribution facilities;~~

~~14.3.3 Generate street maps indicating EDC outage locations;~~

~~14.3.4 Improve the management of resources during a storm;~~

~~14.3.5 Improve the accuracy of identifying the number of customers without electric service;~~

~~14.3.6 Improve the ability to estimate expected restoration times;~~

~~14.3.7 Accurately identify the number and when customers were restored; and~~

~~14.3.8 Effectively support the dispatch of crews and/or service personnel.~~

~~14.4 The SCADA system, at a minimum, shall consist of a remote monitoring and operating ability for all major substation equipment integral to maintaining the reliability of the system. The system will have the ability to:~~

~~14.4.1 Monitor and record critical system load data and major equipment status;~~

~~14.4.2 Provide remote operational control over major equipment; and~~

~~14.4.3 Incorporate generally accepted utility industry safety and security standards.~~

~~15.0 Reporting Specifications and Implementation~~

~~15.1 Planning and Studies Reports, Performance Reports and Major Event Reports provided under this regulation are subject to annual review and audit by the Commission. Each EDC and generation company must maintain sufficient records to permit a review and confirmation of material contained in all required reports.~~

~~15.2 Reports shall be submitted as an original and 5 paper copies with one additional copy submitted electronically to the Secretary, Delaware Public Service Commission, with certification of authenticity by an officer of the corporation. The electronic copy may be posted on the Delaware Public Service Commission's Internet website.~~

~~15.3 Each EDC or generation company may request that information, required under this regulation, be classified as confidential, proprietary and/or privileged material. The requesting party must attest that such information is not subject to inspection by the public or other parties without execution of an appropriate proprietary agreement. Each party requesting such treatment of information is also obligated to file one (1) additional electronic and paper copy of the information, excluding the confidential or proprietary information. The Commission, in accordance with Rule 11, Rules of Practice and Procedure of the Delaware Public Service Commission, effective May 10, 1999, will treat such information as "confidential, not for public release" upon receipt of a properly filed request. Any dispute over the confidential treatment of information shall be resolved by the Commission, designated Presiding Officer or Hearing Examiner.~~

~~15.4 This regulation replaces the Interim Regulation and is effective 10 days after publication in the Delaware Register; however, for the initial 2006 year, Planning and Studies reports are due March 31, 2006; Performance reports are due April 30, 2006, and compliance shall be based upon, in all respects, the standards and requirements of the Interim Regulations. Thereafter, and beginning January 1, 2007, EDC compliance shall be based upon the standards and requirements of these revised regulations.~~

10 DE Reg. 576 (09/01/06)

23 DE Reg. 888 (04/01/20) (Final)