DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.914, R 460.916, R 460.918, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.

Rule 1a. As used in these rules:

(a) “AC” means alternating current at 60 Hertz.

(b) “Affected system” means another electric utility’s distribution system, a municipal electric utility’s distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.

(c) “Affiliate” means that term as defined in R 460.10102(1)(a).

(d) “Alternative electric supplier” means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

“Aggregate Capacity” or “Aggregate Generation Capacity” means the aggregated ongoing operating capacities of all small generator facilities across multiple points of common coupling, within a defined portion of the distribution system.

(e) “Alternative electric supplier distributed generation program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(f) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(g) “Applicant” means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.

(h) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(i) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(j) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding the following holidays: New Year’s Day, Martin Luther King Jr. Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Christmas Eve, Christmas Day, and New Year’s Eve. Election Day, the day after Thanksgiving, and any day that meets the criteria of catastrophic conditions as defined in R 460.702(f) may also be excluded.

(k) “Certified” means an inverter-based system has met acceptable safety and reliability standards by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 2020 edition except that prior to January 1, 2023, inverter-based systems which conform to the UL 1741 January 28, 2010 edition are acceptable.

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

(m) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(n) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(o) “Construction agreement” means an agreement, pursuant to the interconnection standards superseded by R 460.901a to R 460.992, between an interconnection customer and an electric utility that contains timelines and cost estimates for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and identifies design, procurement, installation, and construction requirements associated with installation of the DER.

(p) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(q) “DC” means “direct current.”

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(r) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of exporting active power to a distribution system.

(s) “Distributed generation program” means the distributed generation program approved by the commission and included in an electric utility’s tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(t) “Distribution system” means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(u) “Distribution system study” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined whether a distribution system upgrade was needed to accommodate the proposed project and the cost of a distribution upgrade if required.

(v) “Distribution upgrades” mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER’s connection to the distribution system.

(w) **“**Electric utility” means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, “electric utility” includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) “Electrically coincident” means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

(y) “Electrically remote” means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) “Eligible electric generator” means a methane digester or renewable energy system with a generation capacity limited to a customer’s electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) “Energy storage device” means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

(bb) “Engineering review” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined the suitability of the interconnection equipment including any safety and reliability complications arising from equipment saturation, multiple technologies, and proximity to synchronous motor loads.

Export Capacity: means the maximum possible simultaneous generation of the Generating Facility, and is calculated as the maximum amount of export as permitted by limiting the amount of the Generating Facility's export at the Point of Common Coupling.

(cc) "Facilities study" means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) "Fast track" means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) "Force majeure event" means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause beyond a party's control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) "Full retail rate" means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

"Generating Capacity" means the maximum Nameplate Rating of a Generating Facility in alternating current (AC), except that where such capacity is limited by any of the methods of limiting electrical export; generating capacity shall be the net capacity as limited though the use of such methods (not including inadvertent export).

(gg) "Good standing" means an applicant has paid in full all undisputed bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

(hh) "Governmental authority" means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(ii) "GPS" means global positioning system.

(jj) "Grid network" means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer. (kk) "High voltage distribution" means those parts of a distribution system that operate within a voltage range specified in the electric utility's interconnection procedures. For purposes of these rules, the term "subtransmission" means the same as high voltage distribution.

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(ll) "IEEE" means institute of electrical and electronics engineers.

(mm) "IEEE 1547-2018" means "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as adopted by reference in R 460.902.

(nn) "IEEE 1547.1-2020" means IEEE "Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces," as adopted by reference in R 460.902.

"Inadvertent export" means the potential condition in which a normally non-exporting or limited-exporting DER experiences an unscheduled, export that does not exceed limitations in terms of magnitude or duration as specified in UL 1741 CRD for PCS. ("UL 1741 CRD for PCS" means the Certification Requirement Decision for Power Control Systems for the standard titled " Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources " (March 8, 2019), Underwriters Laboratories Inc., 333 Pfingsten Road, Northbrook IL 60062-2096.)

(oo) “Independent system operator” means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(pp) “Initial review” means the fast track initial review screens described in R 460.946.

(qq) “Interconnection” means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(rr) “Interconnection agreement” means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement shall specify timelines, cost estimates, and payment milestones for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, procurement, installation, and construction requirements associated with installation of the DER. Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.

(ss) “Interconnection coordinator” means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(tt) “Interconnection customer” means the person or entity, which may include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(uu) “Interconnection facilities” mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(vv) “Interconnection procedures” mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) “kW” means kilowatt.

(b) “kWac” means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) “kWh” means kilowatt-hours.

(d) “Legacy net metering program” means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) “Level 1” means a certified project of 20 kWac or less.
(f) “Level 2” means a certified project of greater than 20 kWac and not more than 150 kWac.
(g) “Level 3” means a project of 150 kWac or less that is not certified, or a project greater than 150 kWac and not more than 550 kWac.
(h) “Level 4” means a project of greater than 550 kWac and not more than 1 MWac.
(i) “Level 5” means a project of greater than 1 MWac.
(j) “Level 4 and 5 interconnection agreement” means an interconnection agreement applicable to level 4 and 5 interconnection applications.
“Limited Export” means the exporting capability of a Generating Facility whose Generating Capacity is limited by the use of any configuration or operating mode.
(k) “Low voltage distribution” means those parts of a distribution system that operate with a voltage range specified in the electric utility’s interconnection procedures.
(l) “Mainline” means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.
(m) “Material modification” means a modification to the DER Generating Capacity, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:

(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.
(ii) The cost, timing, or design of any other application.
(iii) The electric utility’s distribution system or an affected system.
(iv) The safety or reliability of the distribution system.

(n) “Methane digester” means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.
(o) “Modified net metering” means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility’s distribution system during a billing period or time-of-use pricing period.
(p) “MW” means megawatt.
(q) “MWac” means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.
(r) “Nameplate capacity” means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation.
(s) “Nameplate rating” means all of the following at which a DER is capable of sustained operation:

(i) Nominal voltage (V).
(ii) Current (A).
(iii) Maximum active power (kWac).
(iv) Apparent power (kVA).
(v) Reactive power (kvar).

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(t) "Nationally recognized testing laboratory" means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.
(u) "Network protector" means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs. (v) "Non-export track" means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility's distribution system, as described in R 460.942.
"Ongoing operating capacity" means the actual simultaneous Generating Capacity, taking into account the operational differences of load offset and export. If the contribution of energy storage to the total contribution is limited by programing of the maximum active power output, use of a power control system, use of a power relay, or some other mutually agreeable, on-site limiting element, only the capacity that is designed to inject electricity to the utility's distribution (other than inadvertent exports and fault contribution) will be used within certain technical screens and evaluations. (w) "Parallel operation" means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.
(x) "Party" or "parties" means an electric utility, applicant, or interconnection customer.
(y) "Point of common coupling" means the point where the DER connects with the electric utility's distribution system.
"Power Control System" means systems or devices which electronically limit or control steady state currents to a programmable limit and certified under UL 1741 CRD for Power Control Systems (PCS) by a nationally recognized testing laboratory.
(z) "Radial supply" means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.
(aa) "Readily available" means no creation of data is required, and little or no computation or analysis of data is required.
(bb) "Reasonable efforts" mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.
(cc) "Regional transmission operator" 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, expansion, operation, and use on a regional and interregional basis.
(dd) "Renewable energy credit" means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.
(ee) "Renewable energy resource" means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.
(ff) "Renewable energy system" means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.
(gg) "Secondary network" means those areas of a distribution system that operate at a secondary voltage level and are networked.

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(hh) "Simplified track" means the procedure for evaluating a level 1 or level 2 proposed interconnection, as described in R 460.940.
(ii) "Site" means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.
(jj) "Spot network" means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.
(kk) "Standard level 1, 2, and 3 interconnection agreement" means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications.
(ll) "Study track" means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.
(mm) "Supplemental review" means the fast track supplemental review screens described in R 460.950.
(nn) "System impact study" means a study to identify and describe the impacts to the electric utility's distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility's distribution system. A system impact study also identifies affected systems.
(oo) "Temporary DER" means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.
(pp) "Transition batch" means the group of interconnection applications processed pursuant to R 460.918.
(qq) "True net metering" means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system, during a billing period or time-of-use pricing period.
(rr) "UL" means underwriters laboratory.
(ss) "UL 1741" means the September 28, 2021 revision of "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources," as adopted by reference in R 460.902.

R 460.902 Adoption of standards by reference.
Rule 2. (1) The standards specified in these rules are adopted by reference as follows:
(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, August 3, 2020 revision, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/Catalog.aspx at a cost of $395.00 at the time of adoption of these rules.
(b) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.
(c) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.

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(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.

(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.

(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.

(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.

(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.

Rule 4. (1) The parties shall attempt to resolve all disputes arising out of the interconnection process, as defined by R 460.901a through R 460.992, according to the provisions of this rule.

(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties shall discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.

(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.

R 460.906 Formal mediation.

Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party's possession on which the party intends to rely to support the party's position.

(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party's email address and file the notice with the commission.

(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.

(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.

(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.

(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.

(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation or formal mediation pursuant to these rules.

(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Appointment of experts.

Rule 8. (1) If a complaint is filed against an electric utility regarding a technical issue, the commission may, at its discretion, appoint 1 to 3 independent experts to investigate the complaint and report findings to the commission.

(2) The experts shall submit a report to the commission with the results and conclusions of their inquiry and may suggest corrective measures for resolving the complaint. The reports of the experts must be received in evidence and the experts made available for cross examination by the parties at any hearing.

(3) The reasonable expenses of experts appointed pursuant to subrule (1) of this rule, including a reasonable hourly fee or fee determined by the commission, must be submitted by these experts to the commission for approval and, if approved, must be funded under subrule (4) of this rule.

(4) An electric utility or alternative electric supplier shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

R 460.910 Waivers.

Rule 10. An electric utility, customer, alternative electric supplier, applicant, or interconnection customer may apply to the commission for a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.

Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement. Interconnection applications with a construction agreement or interconnection agreement executed prior to the effective date of these rules are governed by their construction or interconnection agreement.

R 460.914 Transition non-study group.

Rule 14. (1) Interconnection applications that were filed before the effective date of these rules and that do not meet the eligibility criteria for transition batch study must be placed into the transition non-study group.

(2) An electric utility shall determine whether an interconnection application in the transition non-study group is eligible to go through the simplified track, non-export track, or fast track within 30 business days of the effective date of these rules. Within 30 business days of making the eligibility determination, an electric utility shall commence processing the interconnection application according to the applicable timelines in these rules.

(3) An electric utility shall process incomplete or non-conforming interconnection applications according to R 460.936(7)(a) and (b).

R 460.916 Legacy applications.

Rule 16. (1) For applicants with interconnection applications that have complete distribution system studies and that have entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection must be completed according to existing contractual arrangements.

(2) For applicants that have distribution system studies which were completed by an electric utility within the 12 months prior to the effective date of these rules, but have not entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection application must proceed to an interconnection agreement under R 460.964.

(3) For applicants that have distribution system studies that were conducted and completed more than 6 months before the effective date of these rules, the electric utility may require a facilities study within the transition batch upon a showing that a new study is necessary based on changed circumstances affecting the location of interconnection.

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R 460.918 Transition batch study process.

Rule 18. (1) An electric utility shall begin its transition batch 80 business days after the effective date of these rules.

(2) Interconnection applications are eligible to join the transition batch if all of the following requirements are met:

(a) The application does not qualify for simplified track, non-export track, or fast track.

(b) The application was accepted at any time prior to the start of the transition batch, including prior to the effective date of these rules.

(c) A distribution study on the interconnection application was not completed at any time prior to the effective date of these rules, or a distribution study was completed more than 6 months before the effective date of these rules and an electric utility decided a facilities study was necessary pursuant to R 460.916(3).

(3) An applicant with an eligible interconnection application pursuant to subrule (2) of this rule may join the transition batch by signing a transition batch agreement and paying any required fees before the start of the transition batch.

(4) Pre-application reports may not be required for interconnection applications accepted before the effective date of these rules.

(5) If an applicant with an interconnection application that is pending as of the effective date of these rules and that is otherwise eligible to join the transition batch has not submitted a complete and conforming application, an electric utility shall process the incomplete or non-conforming interconnection application according to R 460.936(7)(a) and (b). If the interconnection application is not deemed complete and conforming prior to an electric utility beginning its interconnection studies, the electric utility shall determine whether the interconnection application may be included in the transition batch study.

(6) The interconnection applications in the transition batch must be studied as a group by an electric utility. DERs in the transition batch that are electrically remote may be studied on an expedited schedule, generally in the order the interconnection applications were deemed complete, but this expedited scheduling may not cause unreasonable delays in the evaluation of the other DERs in the transition batch.

(7) An electric utility shall process the transition batch and provide facilities study results to interconnection applicants within 1 year of the start date. The start date for the transition batch must be specified in an electric utility's draft interconnection procedures and published on an electric utility's public website.

(8) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in the transition batch. The scoping meetings must meet the following requirements:

(a) All meetings must, to the extent feasible, take place within the first 30 days of the transition batch.

(b) An electric utility shall not begin studies within the transition batch until it has held a scoping meeting with every applicant that had agreed to participate in a meeting. An electric utility may begin the batch study if 1 or more applicants is unreasonably delaying a meeting.

(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.

(d) During the scoping meeting, an electric utility shall identify and communicate to each applicant the studies it plans to perform and provide the cost of the transition batch study using either fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the transition batch throughout the batch study.

(9) The transition batch process must include a system impact study and a facilities study. An electric utility may specify additional studies it may perform on the transition batch in its interconnection procedures.

(10) Electrically coincident DERs within the transition batch are considered to have equal priority with each other.

(11) An electric utility shall comply with R 460.960(1) and (2) when conducting a system impact study. However, applicants with interconnection applications that have had an engineering review completed within the 6 months prior to the effective date of these rules may not be required to pay for a new system impact study.

(12) An electric utility shall comply with R 460.962(1) when conducting a facilities study.

(13) An electric utility shall provide written study results to each applicant at the completion of each study during the transition batch. An electric utility shall offer to hold at least 1 conference call with each transition batch applicant at the completion of each study. An electric utility may choose to group the consultation regarding multiple projects by 1 applicant and its affiliates into the same conference call. This conference call must provide a summary of outcomes and respond to questions from applicants. Where possible, conferences regarding the study results should be held within 30 business days following completion of the study.

(14) Within 40 business days following completion of the study, an applicant shall choose either to continue in the transition batch or withdraw. The fee for the next study in the transition batch is due by the end of the 40 business day period, unless extended by the electric utility. Applicants that withdraw from the transition batch may reapply with a new interconnection application.

(15) Applicants may reduce the capacity of the DER by up to 20% during the decision period between studies, including up to and through the conclusion of the system impact study. If an applicant wants to increase the capacity of the DER by any amount or decrease the capacity of the DER by more than 20%, an electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(16) Within 45 days of receiving the final transition batch study report, an applicant shall notify the electric utility whether it intends to proceed to an interconnection agreement pursuant to R 460.964 or withdraw. Failure to notify an electric utility within the required time period shall result in the interconnection application being withdrawn.

(17) Under circumstances where an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, other interconnection applications in the transition batch must continue to progress. If feasible, due to the status of the transition batch study, the delayed interconnection application may rejoin the transition batch study after

the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, may also rejoin the batch study at a later date, if feasible, due to the status of the batch study.

(18) A transition batch study is considered complete 45 business days after all transition batch applicants, except those applicants whose DERs are still causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, have withdrawn, or have received a final transition batch study report.

R 460.920 Electric utility interconnection procedures.

Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms within 30 business days of the effective date of these rules.

(2) The commission shall issue its order approving, rejecting, or modifying the proposed interconnection procedures and forms within 360 days of the effective date of these rules. If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another party in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

(3) Until the commission accepts, rejects, or modifies an electric utility's interconnection procedures and forms, the electric utility may use the proposed interconnection procedures and forms when processing interconnection applications with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms.

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, include all of the following:

(a) All necessary applications, forms, and relevant template agreements.

(b) A schedule of all applicable fixed fees and fee caps.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Acceptable methods or standards for power-limited export DERs in compliance with allowances in R 460.980 .

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

(m) Details describing how an energy storage device may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.

(o) Examples of modifications that are not material modifications, acceptable material modifications, and unacceptable material modifications.

(p) The procedure for performing a material modification review.

(6) An electric utility shall obtain commission approval to revise its interconnection procedures.

R 460.922 Online applications and electronic submission.

Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.

(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:

(a) These rules and interconnection procedures in an electronically searchable format.

(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.

(c) Sample documents including, at a minimum, a 1-line diagram with required labels.

(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.

(e) Directions for the submission of applications.

R 460.924 Communications.

Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process.

(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.

(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Initial fees.

Rule 26. (1) After the effective date of these rules, fees for the pre-application report, the simplified track, the non-export track, the fast track, and the study track may not exceed the initial fee caps listed in subrule (2) of this rule, and the caps must remain in effect until interconnection procedures are approved by the commission under R 460.920.

(2) The initial fee amounts for all levels of DERs are as follows:

(a) The pre-application report fee may not exceed $300.

(b) The simplified track fee and any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.

(c) The non-export track fee may not exceed $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(d) The fast track initial review fee is $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(e) The transition batch fee for interconnection application review and the scoping meeting may not exceed $300.

(f) The fee for a fast track supplemental review including all review screens may not exceed $5,000.

(g) The study track fee for interconnection application review and the scoping meeting may not exceed $300.

(h) The system impact study fee may not exceed $30,000.

(i) The facilities study fee may not exceed $30,000.

(3) The initial fees caps listed in subrule (2) of this rule, and any fixed fees subject to the initial fee caps charged by the electric utility, must be displayed prominently on the electric utility's interconnection website.

(4) An electric utility that expects to incur costs greater than the initial fee caps listed in subrule (2) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.928 Fee and fee cap modifications.

Rule 28. (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the initial fee caps specified in R 460.926(2)(a), (b), (c), (d), (e), and (g), and any other fixed fees the electric utility considers necessary.

(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(2)(f), (h), and (i), and any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.

(3) The fixed fees must be specific to level size and be based on estimates of reasonable costs to perform the applicable service or study. The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.

(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.

(5) The fixed fees and fee caps that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.
(6) Any modification of fees may not be applicable to fees already paid.
(7) An electric utility that expects to incur costs greater than its prevailing fee caps in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.930 Pre-application report request form.
Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.
(2) The pre-application report request form must include all of the following information:
(a) Project contact information, including name, address, phone number, and email address.
(b) Project location, as accurately as can be identified, which may be given by any of the following:
(i) Street address with nearby cross streets and town.
(ii) An aerial map with location clearly marked.
(iii) GPS coordinates.
(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.
(d) Whether the DER is any of the following:
(i) Solar.
(ii) Wind.
(iii) Cogeneration.
(iv) Storage.
(v) Solar with storage.
(vi) Other type of DER.
(e) Nameplate capacity of the DER types in alternating current kW.
(f) Whether the DER configuration is single or 3-phase.
(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.
(h) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.
(i) Whether the location is new construction.

R 460.932 Pre-application report.
Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.

(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.

(3) The pre-application report must include all of the following information:

(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.

(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.

(f) Nominal distribution circuit voltage at the proposed point of common coupling.

(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.

(h) Approximate circuit distance between the proposed point of common coupling and the substation.

(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.

(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.

(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.

(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.

(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.

(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.

(o) Whether or not the area has been identified as having a prior affected system.

(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available. The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.

(6) An electric utility shall provide the data required in the pre-application report to the applicant within 25 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant.

R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.

(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:

(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.

(b) An enforceable option to purchase or acquire a leasehold site for this purpose.

(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.

(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature on the application.

(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.

Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.

(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.

(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.

(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.

(5) For interconnection applications with proposed DERs that fall into levels 4 and above, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.

(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric utility has received the interconnection application, the application attachments, and

payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.

(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.

(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the simplified track, non-export track, fast track, or study track.

(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.

(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a public interconnection list, which is available in a sortable spreadsheet format, and provide it to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.

(2) The public interconnection list must include all of the following:

(a) An application identifier.

(b) The date that the electric utility received the application.

(c) The date that the electric utility considered the application to be complete and conforming.

(d) Whether the application is on the simplified track, non-export track, fast track, or study track.

(e) The proposed DER nameplate capacity.

(f) The proposed DER interconnection size level.

(g) The DER technology type.

(h) The county and township in which the proposed point of common coupling will be located.
(i) The current status of the application's progress in the interconnection process.
(j) The labels, names, or identifiers of the distribution circuit and substation.

R 460.940 Simplified track review.
Rule 40. (1) Level 1 and 2 applications, including applications that include an energy storage device so the ongoing operating capacity meets the requirements of level 1 or level 2, must be processed using the simplified track.

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(2) Within 10 business days after notifying an applicant that the application had been accepted, an electric utility shall perform a review by using up to all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant if any interconnection facilities, distribution upgrades, further study, or application modifications are required for safe and reliable interconnection to the electric utility's distribution system or for tariff compliance. If an electric utility chooses to perform a review by using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require application modification or further study.
(3) If the utility review notification indicates that no further study or application modifications are required, the applicant shall proceed under R 460.964 to an interconnection agreement.
(4) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business days that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (2) of this rule.
(5) If further study is required, the electric utility and the applicant shall decide whether to proceed to a supplemental review under R 460.950 or the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and to notify the electric utility. In the absence of this notification, the electric utility may withdraw the application.

R 460.942 Non-export track review.
Rule 42. (1) Interconnection applications for DERs that will limit injection of electric energy into an electric utility's distribution system are eligible for evaluation under the

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non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

(2) Subject to review and approval by the commission, an electric utility may limit the eligibility of the non-export track in its interconnection procedures based on the characteristics of its distribution system.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility for assistance in determining whether a non-export track review will be sufficient or the study track is necessary. The electric utility shall provide the applicant assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require interconnection facilities, distribution upgrades, further study, or application modifications.

(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install within 10 business days of the applicant being notified. Within 10 business days of receiving the equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.

(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business day that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (4) of this rule.

(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.

(6) When an applicant changes from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application.

R 460.944 Fast track applicability.

Rule 44. (1) Level 3 and level 4 applications in which the DER is not proposing to interconnect with the electric utility's high voltage distribution system are eligible for the fast track. These level 3 and level 4 applications may include applications that provide for the use of an energy storage device so the export of power meets the requirements of level 3 or level 4.

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

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(3) The electric utility may waive application of 1, some, or all of the initial review screens.

(4) Within 20 business days after an electric utility receives a complete and conforming application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens.

(5) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The electric utility shall consider 100% of applicable loading, if available, instead of 15% of line section peak load for Level 1 and Level 2 DER. In the event daytime loading data is not available, the data must be collected by January 2023 and shall not consider as part of the aggregate generation, for purposes of this screen, DER capacity known to be already reflected in the minimum load data. This screen does not apply to Level 1 and Level 2 non export DER.

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(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's maximum load or 50 kWac.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling. This screen does not apply to Level 1 DER.

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers. This screen does not apply to Level 1 DER.

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen
3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER export capacity, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the DER's nameplate rating must be less than 250 kWac. This screen does not include substation voltage regulators.

(6) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection

application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection agreement must proceed under R 460.962.

(7) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (4) of this rule.

(d) Withdraw the interconnection application.

(8) If the applicant does not select a course of action under subrule (7) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant's request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(7).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(4).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (6) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2)

(3) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(4) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(5) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, an electric utility shall perform a supplemental review and notify the applicant of the results. The supplemental review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a system impact study if the DER passes the applied supplemental review screens.

(6) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (7) and (8) of this rule. All of the following must be applied by the electric utility:

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in subrule (6)(a) of this rule. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

Deleted: An electric utility may include additional supplemental review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, the electric utility shall provide a detailed technical rationale for the inclusion of each supplemental review screen. If an additional screen negates or undermines any of the supplemental review screens specified in subrule (6) of this rule, the rationale must include an explanation of the technical justification for the additional screen

Deleted: .

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section may not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal and emergency ampacity.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(7) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(8) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(9) For subrules (7) and (8) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the simplified track, the non-export track, or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the simplified track or the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted pursuant to R 460.936, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), (d), or (e) of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(4) An electric utility shall study all interconnection applications that qualify for study track either individually or in a batch study process. An electric utility shall not study 1 or more applications individually and at the same time study 1 or more different applications as part of a batch.

(5) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities impact study fee.

R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs.

(a) An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility has elected to study all interconnection applications that qualify for study track individually.

(b) An electric utility determined the application to be complete and conforming.

(c) An application qualifies for study track pursuant to R 460.952.

(d) An interconnection application has a pre-application report, when required by R 460.936(2).

(e) An applicant has paid all required fees.

(f) An applicant has signed and returned an individual study agreement.

(5) If an electric utility anticipated that it would use a batch study process but received only 1 interconnection application that qualified for the study track, the electric utility shall consider the first day of what would have been the batch study process to be the day the application was determined to be complete and conforming and shall use the individual study process to evaluate the application with all applicable timelines.

R 460.956 Batch study process.

Rule 56. (1) This rule applies only to those electric utilities that have elected to study DERs that qualify for study track in a batch process.

(2) A batch consists of 2 or more interconnection applications that will be studied as a group by the electric utility. One or more DERs in the batch that are electrically remote may be studied on an expedited schedule, but expedited scheduling of 1 or more DERs may not cause unreasonable delays in the evaluation of the other DERs in the same batch.

(3) An electric utility shall process at least 1 batch per year. The start and end dates for each batch study must be published on the electric utility’s public website not less than 60 days prior to the start of the batch.

(4) Interconnection applications that meet all of the following requirements must be admitted into a batch study:

(a) The electric utility elected to study all interconnection applications that qualify for study track in a batch study process.

(b) The electric utility considered the application complete and conforming within a 1-year period immediately before the batch study commences.
(c) The accepted application qualifies for study track pursuant to R 460.952.
(d) The interconnection application has a pre-application report when required by R 460.930(2).
(e) The applicant has paid all required fees including any milestone payments as described in the electric utility's interconnection procedures.
(f) The applicant has signed a batch study agreement.
(5) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in a batch. The scoping meetings and the electric utility must meet all of the following requirements:
(a) All meetings must, to the extent feasible, take place within 30 days of the batch start date.
(b) An electric utility shall not begin studies within a batch until it has held a scoping meeting with every applicant who agreed to participate in a meeting. An electric utility may begin the batch study if an applicant is unreasonably delaying a meeting.
(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.
(d) During the scoping meeting, the electric utility shall identify and communicate to each applicant the studies it plans to perform and estimate the cost of the batch study, using either the fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the batch throughout the batch study.
(6) The batch process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. The electric utility may specify additional studies it may perform on a batch study in its interconnection procedures.
(7) Interconnection applications within a batch must be considered to have equal priority with each other.
(8) An electric utility shall follow R 460.960(1) and (2) when conducting a system impact study.
(9) An electric utility shall follow R 460.962(1) when conducting a facilities study.
(10) An electric utility shall provide written study results to each applicant at the completion of each study during the batch study. An electric utility shall offer to hold a conference call with each batch applicant at the completion of each study phase, with the electric utility making reasonable efforts to accommodate applicants' availability when scheduling the call. An electric utility may choose to group the consultation of multiple projects by the applicant and its affiliates into the same conference call. The conference call must provide a summary of outcomes and answer questions from applicant. All conferences regarding the study results should be held within 30 business days following completion of each study phase.
(11) Within 45 business days following the completion of each study phase, the applicant shall choose to either continue to the next study phase of the batch study or withdraw. The fee for the next study phase in the batch study is due by the end of the 45

business days, unless extended by the electric utility. An applicant that withdraws from the study may reapply with a new interconnection application.

(12) Applicants may reduce the capacity of the DER by up to 20% during the decision period between study phases until the conclusion of the system impact study. If the applicant wants to increase the capacity of the DER, the electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(13) Within 45 business days of the applicant receiving the final batch study report from the electric utility, the applicant shall notify the electric utility of its plan to proceed to R 460.964 for an interconnection agreement or withdraw its interconnection application. If the applicant fails to notify the electric utility within 45 business days, the electric utility may withdraw the interconnection application.

(14) If an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, the other interconnection applications in the batch must continue to progress through the batch study process. If feasible, considering the status of the batch study, the delayed interconnection application may rejoin the batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, may rejoin the batch study at a later date, if feasible, considering the status of the batch study.

(15) A batch study is considered complete 45 business days after all batch applicants, except those applicants whose DERs are either causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, pursuing formal mediation under R 460.906, or pursuing a complaint under R 792.10439 to R 792.10446, have withdrawn, voluntarily or otherwise, or have received the final study results from the electric utility.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to those electric utilities that have elected to individually study DERs that qualify for study track.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.

(4) The scoping meeting may occur in-person or via telecommunications.

(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study,

or an interconnection agreement and the basis for that decision, and 1 of the following must occur:

(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.

(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.

(c) The interconnection application must proceed to R 460.964 for an interconnection agreement.

R 460.960 System impact study agreement, scope, procedure, and review meeting.

Rule 60. (1) For all DERs being studied individually or as part of a batch, all of the following apply:

(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.

(b) A system impact study agreement must include all of the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.

(iv) A timeline for completion of the system impact study.

(v) A list of the information that must be provided to the applicant in the system impact study report.

(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.

(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.

(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.

(2) For DERs being studied as part of a batch, an electric utility may request reasonable additional data from the applicant during the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the batch study within the 1-year timeframe specified in R 460.956. An electric utility may not be found in violation of these rules when 1 or more applicants impede the batch study process through applicant delays, demands, complaints, litigation, objections, or other similar actions.

(3) For DERs being studied individually, all of the following shall apply:

(a) The electric utility shall complete the system impact study and the system impact study report. If necessary, the electric utility shall transmit a facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data**.**

(b) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subrule (3)(a) of this rule.

(c) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(d) Upon request by the applicant pursuant to subrule (3)(c) of this rule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(e) At the system impact study review meeting, the electric utility shall offer the applicant all of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(iii) Withdraw the interconnection application.

(f) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.

(g) The system impact study review meeting may occur in-person or via telecommunications.

R 460.962 Facilities study agreement, scope, procedure; review meeting.

Rule 62. (1) For DERs being studied individually or as part of a batch, all of the following apply:

(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. If no system impact study was performed, the electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.

(b) The facilities study agreement must include the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) A timeline for completion of the facilities study.

(iv) A list of the information that will be provided to the applicant in the facilities study report.

(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.
(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. The electric utility shall provide cost estimates that are detailed and itemized.
(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.
(2) For DERs being studied individually, all of the following are required:
(a) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee.
(b) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:
(i) Request a facilities study review meeting with the electric utility.
(ii) Proceed to an interconnection agreement pursuant to R 460.964.
(iii) Withdraw the interconnection application.
If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.
(c) Upon request by the applicant pursuant to subrule (2)(b)(i) of this rule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.
(d) At the facilities study review meeting, the electric utility shall offer both of the following options:
(i) Proceed to an interconnection agreement pursuant to R 460.964.
(ii) Withdraw the interconnection application.
(e) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.
(f) The facilities study review meeting may be conducted in-person or via telecommunications.

R 460.964 Interconnection agreement.
Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement to an applicant within 3 business days of reaching this stage.
(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall

provide its standard level 1, 2, and 3 interconnection agreement with modifications to address required construction activities, construction milestone timing, and cost to an applicant within 5 business days of reaching this stage. The applicant and electric utility shall mutually agree on the timing of construction milestones.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the standard level 1, 2, and 3 interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the standard level 1, 2, and 3 interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility did not receive the signed standard level 1, 2, and 3 interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subrule 3(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, the formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the standard level 1, 2, and 3 interconnection agreement within 10 business days of the applicant returning the signed standard level 1, 2, and 3 interconnection agreement.

(5) For level 4 or 5 projects, the electric utility shall provide its level 4 and 5 interconnection agreement within 10 business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the level 4 and 5 interconnection agreement must contain either timelines for completion of activities and estimates of construction costs or a timetable when these requirements can be determined. The interconnection agreement must include a payment schedule that corresponds to the milestones established and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the level 4 and 5 interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility does not receive the signed level 4 and 5 interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subrule (6)(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility’s standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting batch studies, if either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment prior to the electric utility beginning the study phase of the next batch study pursuant to R 460.956, the electric utility may not include the interconnection application in the system baseline for conducting the next batch study. If the interconnection application is electrically coincident with other interconnection applications in the next batch study, the electric utility may require the withdrawal of the interconnection application.

(ii) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant prior to being incurred. The cost may not exceed 125% of the estimate without the consent of the applicant prior to the costs being incurred.

(9) A party’s obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:

(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.

(b) Propose the earliest alternate date when it can attain this and future milestones.

(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.

(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:

(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.

(b) The milestone under question has been previously delayed.

(c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.

(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.

(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades.

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute. Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER.

(b) If the applicant's previous aggregate payments exceed its costs under the construction agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations, provided that these modifications do not alter the rights or obligations of the interconnection customer.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. The electric utility's interconnection procedures must describe the technical requirements of these items.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the standard level 1, 2, and 3 interconnection agreement or level 4 and 5 interconnection agreement.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days.

(4) If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect

the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within either of the following:
(a) Ten business days of receiving the notification from the applicant pursuant to subrule (2) of this rule, for level 1, 2, and 3 applications.
(b) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to subrule (2) of this rule for level 4 and 5 applications.
(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests.
(a) If the electric utility waives this right, it shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.
(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.
(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.
(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.
(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.
(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.
(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report.
(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.
(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.
(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.

R 460.968 Authorization required prior to parallel operation.

Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:

(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.

(b) The applicant complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.

(c) The applicant complied with all applicable local, state, and federal requirements.

(d) The electric utility received full payments for all outstanding bills.

(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.

(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.

(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.

R 460.970 Cost allocation of interconnection facilities and distribution upgrades**.**

Rule 70. Costs for interconnection facilities and distribution upgrades must be classified into 1 of the following categories:

(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs. These costs must be assigned to the cost-causing applicant.

(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

Commented [SR5]: It appears there is no queue planned for cost allocation recovery and these processes are envisioned to support projects undergoing group study related processes? This may be helpful, but does may not go far enough to facilitate smart utility upgrade processes to most cost effectively unlock hosting capacity.

R 460.974 Interconnection metering and communications.
Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.
(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.
Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.
(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.
Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:
(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).
(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).
(c) Termination of interconnection by mutual agreement.
(d) Distribution system emergency, but only for the time necessary to resolve the emergency.
(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.
(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.
(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.
(h) Other material noncompliance with the interconnection agreement.
(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.
(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

R 460.980 Capacity of the DER.

Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the new ongoing operating capacity of the DER. The maximum capacity of a DER is the aggregate nameplate capacity or may be limited as described in the electric utility's interconnection procedures.

(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures.

(3) The electric utility's interconnection procedures must include acceptable methods for power limited export DER including, so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported.

(3a) Limited-Export and Non-Exporting Generating Facilities

An electric utility shall allow interconnection of limited-export or non-exporting generating facilities and energy storage according to these procedures.

If a Generating Facility uses any configuration or operating mode in this Section, subparagraphs 1 through 6 to limit the export of electrical power across the Point of Common Coupling, then the Generating Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a Generating Facility must comply with the limits in subparagraphs 5 or 6. The Generating Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement. Other means not listed in this Section may be utilized to limit export if mutually agreed upon by the Utility and Applicant.

1. Reverse Power Protection: To ensure power is never exported across the Point of Common Coupling, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.
2. Minimum Power Protection: To ensure at least a minimum amount of power is imported across the Point of Common Coupling at all times (and, therefore, that power is not exported), an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay.
3. Relative Distributed Energy Resource Rating: This option requires the Nameplate Rating of the generating unit, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional Protective Functions is not required to ensure that power will not be exported to the Electric Delivery System. This option requires the generating unit capacity to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months.

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4. Configured Power Rating: A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating.

5. Limited Export Utilizing Inverters or Control Systems: Generating Facilities may utilize, a Nationally Recognized Testing Laboratory “NRTL”) Certified Power Control System and inverter system that results in the Generating Facility disconnecting from the Electric Delivery System, ceasing to energize the Electric Delivery System or halting energy production within 2 seconds if the period of continuous Inadvertent Export exceeds 30 seconds. Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the Generating Facility entering an operational mode where no energy is exported across the Point of Common Coupling to the Electric Delivery System.

6. Limited Export Using Mutually Agreed-Upon Means: Generating Facilities may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export to levels mutually agreed upon by the Applicant and the Utility. The limits may be based on technical limitations of the Interconnection Customer’s equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

R 460.982 Modification of the interconnection application.

Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform a cursory evaluation to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business day.

(2) The electric utility shall not be required to accept or implement a modification to the electric utility’s distribution system or generation assets that is proposed by an applicant or affected system operator.

(3) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.

(4) For a proposed modification which the electric utility has determined is a material modification, the applicant may request a material modification review to determine whether the material modification is an acceptable material modification or an unacceptable material modification. The electric utility shall complete the material

modification review and determine which of the following options are available to the applicant:

(a) If the modification is an unacceptable material modification, the applicant may withdraw the modification or withdraw the application.

(b) If the modification is an acceptable material modification and requires minimal or no restudy, the application study activities will resume with the modification and no change to the timing.

(c) If the modification is an acceptable material modification but requires restudy, the electric utility shall expedite the restudy. The applicant shall pay any required fee for the expedited restudy.

(5) The applicant may request a 1-hour consultation to discuss the results of the material modification review.

(6) The applicant shall notify the electric utility of its selection pursuant to subrule (4) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.

(7) If the proposed modification is determined not to be a material modification or is determined to be an acceptable material modification, the electric utility shall notify the applicant that the proposed modification has been accepted.

(8) If the modification is considered an unacceptable material modification, the applicant shall withdraw the proposed modification, or initiate mediation pursuant to R 460.904 or R 460.906, or file a complaint pursuant to R 792.10439 to R 792.10446 within 10 business days of receipt of the decision, or proceed with a new interconnection application for this modification. If the applicant does not provide its determination within the 10 business days, the electric utility may consider the interconnection application withdrawn.

(9) Any modification to the interconnection application or to the DER that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.

(10) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.

(11) Replacing a component with another component that has near-identical characteristics does not constitute a material modification.

(12) The electric utility's interconnection procedures must provide examples of modification that are not material modifications, acceptable material modifications, and unacceptable material modifications.

(13) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.

Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant may not begin any material modification to the DER until the electric utility has accepted the new interconnection application and completed at least one of the following:
(a) An initial review.
(b) A supplemental review.
(c) A system impact study.
(d) A facilities study.

R 460.986 Insurance.
Rule 86. (1) An applicant interconnecting a level 1 or 2 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.
(2) An electric utility shall not require an applicant interconnecting a level 1 or 2 project to name the electric utility as an additional insured party.
(3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.
(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.
(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $3,000,000.

R 460.988 Easements and rights-of-way.
Rule 88. If an electric utility line extension is required to accommodate an interconnection, the applicant is responsible for procurement and the cost of providing and obtaining easements or rights-of-way.

R 460.990 Interconnection penalties.
Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Catastrophic conditions.
Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to catastrophic conditions as defined in R 460.702(f). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.
Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.
Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.
(2) Within 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.
(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.
(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.
(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.
(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.
(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.
(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the

previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

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(8) An applicant shall notify the electric utility of plans for any material modification to the project. An applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application, including any necessary system impact study or facilities study. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on the legacy net metering program application the date that the customer applied for

interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.

(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit the distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.

(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.

(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.

(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

R 460.1006 Distributed generation program application and fees.

Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for

interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the distributed generation program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.

(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:

(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility’s notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.

(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(5) If a customer’s distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer’s application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.

(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility’s distributed generation program tariff sheet or in the alternative electric supplier’s distributed generation program plan.

(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer’s interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.

Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.

(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.
(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.
(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.
Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.
Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:
(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.
(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.
(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.
(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:
(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.
(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer's power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer's power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility.

R 460.1022 Renewable energy credits.

Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.

(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.

(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.

Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.

Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.914, R 460.916, R 460.918, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.

Rule 1a. As used in these rules:

(a) “AC” means alternating current at 60 Hertz.

(b) “Affected system” means another electric utility’s distribution system, a municipal electric utility’s distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.

(c) “Affiliate” means that term as defined in R 460.10102(1)(a).

(d) “Alternative electric supplier” means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

(e) “Alternative electric supplier distributed generation program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(f) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(g) “Applicant” means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.

(h) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(i) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(j) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding the following holidays: New Year’s Day, Martin Luther King Jr. Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Christmas Eve, Christmas Day, and New Year’s Eve. Election Day, the day after Thanksgiving, and any day that meets the criteria of catastrophic conditions as defined in R 460.702(f) may also be excluded.

(k) “Certified” means an inverter-based system has met acceptable safety and reliability standards by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 2020 edition except that prior to January 1, 2022, inverter-based systems which conform to the UL 1741 January 28, 2010 edition are acceptable.

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

(m) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(n) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(o) “Construction agreement” means an agreement, pursuant to the interconnection standards superseded by R 460.901a to R 460.992, between an interconnection customer and an electric utility that contains timelines and cost estimates for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and identifies design, procurement, installation, and construction requirements associated with installation of the DER.

(p) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(q) “DC” means “direct current.”

(r) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of exporting active power to a distribution system.

(s) “Distributed generation program” means the distributed generation program approved by the commission and included in an electric utility’s tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(t) “Distribution system” means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(u) “Distribution system study” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined whether a distribution system upgrade was needed to accommodate the proposed project and the cost of a distribution upgrade if required.

(v) “Distribution upgrades” mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER’s connection to the distribution system.

(w) **“**Electric utility” means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, “electric utility” includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) “Electrically coincident” means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

(y) “Electrically remote” means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) “Eligible electric generator” means a methane digester or renewable energy system with a generation capacity limited to a customer’s electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) “Energy storage device” means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

(bb) “Engineering review” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined the suitability of the interconnection equipment including any safety and reliability complications arising from equipment saturation, multiple technologies, and proximity to synchronous motor loads.

(cc) “Facilities study” means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) “Fast track” means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) “Force majeure event” means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause beyond a party's control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) "Full retail rate" means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

(gg) "Good standing" means an applicant has paid in full all undisputed bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

(hh) "Governmental authority" means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(ii) "GPS" means global positioning system.

(jj) "Grid network" means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer.

(kk) "High voltage distribution" means those parts of a distribution system that operate within a voltage range specified in the electric utility's interconnection procedures. For purposes of these rules, the term "subtransmission" means the same as high voltage distribution.

(ll) "IEEE" means institute of electrical and electronics engineers.

(mm) "IEEE 1547-2018" means "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as adopted by reference in R 460.902.

(nn) "IEEE 1547.1-2020" means IEEE "Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces," as adopted by reference in R 460.902.

(oo) "Independent system operator" means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(pp) "Initial review" means the fast track initial review screens described in R 460.946.

(qq) "Interconnection" means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(rr) "Interconnection agreement" means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement shall specify timelines, cost estimates, and payment milestones for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, procurement, installation, and construction requirements associated with installation of the DER.

Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.

(ss) "Interconnection coordinator" means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(tt) "Interconnection customer" means the person or entity, which may include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(uu) "Interconnection facilities" mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(vv) "Interconnection procedures" mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) "kW" means kilowatt.

(b) "kWac" means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) "kWh" means kilowatt-hours.

(d) "Legacy net metering program" means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) "Level 1" means a certified project of 20 kWac or less.

(f) "Level 2" means a certified project of greater than 20 kWac and not more than 150 kWac.

(g) "Level 3" means a project of 150 kWac or less that is not certified, or a project greater than 150 kWac and not more than 550 kWac.

(h) "Level 4" means a project of greater than 550 kWac and not more than 1 MWac.

(i) "Level 5" means a project of greater than 1 MWac.

(j) "Level 4 and 5 interconnection agreement" means an interconnection agreement applicable to level 4 and 5 interconnection applications.

(k) "Low voltage distribution" means those parts of a distribution system that operate with a voltage range specified in the electric utility's interconnection procedures.

(l) "Mainline" means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.

(m) "Material modification" means a modification to the DER nameplate rating, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. Replacing a component with a component with near-identical characteristics does not constitute a material modification. For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:

(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.

(ii) The cost, timing, or design of any other application.

(iii) The electric utility's distribution system or an affected system.

(iv) The safety or reliability of the distribution system.

(n) "Methane digester" means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.

(o) "Modified net metering" means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system during a billing period or time-of-use pricing period.

(p) "MW" means megawatt.

(q) "MWac" means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.

(r) "Nameplate capacity" means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation.

(s) "Nameplate rating" means all of the following at which a DER is capable of sustained operation:

(i) Nominal voltage (V).

(ii) Current (A).

(iii) Maximum active power (kWac).

(iv) Apparent power (kVA).

(v) Reactive power (kvar).

(t) "Nationally recognized testing laboratory" means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.

(u) "Network protector" means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs.

(v) "Non-export track" means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility's distribution system, as described in R 460.942.

(w) "Parallel operation" means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.

(x) "Party" or "parties" means an electric utility, applicant, or interconnection customer.

(y) "Point of common coupling" means the point where the DER connects with the electric utility's distribution system.

(z) "Radial supply" means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.

(aa) "Readily available" means no creation of data is required, and little or no computation or analysis of data is required.

(bb) “Reasonable efforts” mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.

(cc) “Regional transmission operator” 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, expansion, operation, and use on a regional and interregional basis.

(dd) “Renewable energy credit” means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.

(ee) “Renewable energy resource” means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(ff) “Renewable energy system” means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(gg) “Secondary network” means those areas of a distribution system that operate at a secondary voltage level and are networked.

(hh) “Simplified track” means the procedure for evaluating a level 1 or level 2 proposed interconnection, as described in R 460.940.

(ii) “Site” means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.

(jj) “Spot network” means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.

(kk) “Standard level 1, 2, and 3 interconnection agreement” means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications.

(ll) “Study track” means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.

(mm) “Supplemental review” means the fast track supplemental review screens described in R 460.950.

(nn) “System impact study” means a study to identify and describe the impacts to the electric utility’s distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility’s distribution system. A system impact study also identifies affected systems.

(oo) “Temporary DER” means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.

(pp) “Transition batch” means the group of interconnection applications processed pursuant to R 460.918.

(qq) “True net metering” means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility’s distribution system, during a billing period or time-of-use pricing period.

(rr) “UL” means underwriters laboratory.

(ss) "UL 1741" means the August 3, 2020 revision of "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources," as adopted by reference in R 460.902.

R 460.902 Adoption of standards by reference.

Rule 2. (1) The standards specified in these rules are adopted by reference as follows:

(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, August 3, 2020 revision, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/Catalog.aspx at a cost of $395.00 at the time of adoption of these rules.

(b) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.

(c) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.

(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.

(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.

(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.

(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.

(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.

Rule 4. (1) The parties shall attempt to resolve all disputes arising out of the interconnection process, as defined by R 460.901a through R 460.992, according to the provisions of this rule.

(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission

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staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties shall discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.

(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.

R 460.906 Formal mediation.

Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party's possession on which the party intends to rely to support the party's position.

(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party's email address and file the notice with the commission.

(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.

(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.

(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.

(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.

(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation or formal mediation pursuant to these rules.

(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Appointment of experts.

Rule 8. (1) If a complaint is filed against an electric utility regarding a technical issue, the commission may, at its discretion, appoint 1 to 3 independent experts to investigate the complaint and report findings to the commission.

(2) The experts shall submit a report to the commission with the results and conclusions of their inquiry and may suggest corrective measures for resolving the complaint. The reports of the experts must be received in evidence and the experts made available for cross examination by the parties at any hearing.

(3) The reasonable expenses of experts appointed pursuant to subrule (1) of this rule, including a reasonable hourly fee or fee determined by the commission, must be submitted by these experts to the commission for approval and, if approved, must be funded under subrule (4) of this rule.

(4) An electric utility or alternative electric supplier shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

R 460.910 Waivers.

Rule 10. An electric utility, customer, alternative electric supplier, applicant, or interconnection customer may apply to the commission for a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.

Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement. Interconnection applications with a construction agreement or interconnection agreement executed prior to the effective date of these rules are governed by their construction or interconnection agreement.

R 460.914 Transition non-study group.

Rule 14. (1) Interconnection applications that were filed before the effective date of these rules and that do not meet the eligibility criteria for transition batch study must be placed into the transition non-study group.

(2) An electric utility shall determine whether an interconnection application in the transition non-study group is eligible to go through the simplified track, non-export track, or fast track within 30 business days of the effective date of these rules. Within 30 business days of making the eligibility determination, an electric utility shall commence processing the interconnection application according to the applicable timelines in these rules.

(3) An electric utility shall process incomplete or non-conforming interconnection applications according to R 460.936(7)(a) and (b).

R 460.916 Legacy applications.
Rule 16. (1) For applicants with interconnection applications that have complete distribution system studies and that have entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection must be completed according to existing contractual arrangements.
(2) For applicants that have distribution system studies which were completed by an electric utility within the 12 months prior to the effective date of these rules, but have not entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection application must proceed to an interconnection agreement under R 460.964.
(3) For applicants that have distribution system studies that were conducted and completed more than 12 months before the effective date of these rules, the electric utility may require a facilities study within the transition batch upon a showing that a new study is necessary based on changed circumstances affecting the location of interconnection.

R 460.918 Transition batch study process.
Rule 18. (1) An electric utility shall begin its transition batch 80 business days after the effective date of these rules.
(2) Interconnection applications are eligible to join the transition batch if all of the following requirements are met:
(a) The application does not qualify for simplified track, non-export track, or fast track.
(b) The application was accepted at any time prior to the start of the transition batch, including prior to the effective date of these rules.
(c) A distribution study on the interconnection application was not completed at any time prior to the effective date of these rules, or a distribution study was completed more than 12 months before the effective date of these rules and an electric utility decided a facilities study was necessary pursuant to R 460.916(3).
(3) An applicant with an eligible interconnection application pursuant to subrule (2) of this rule may join the transition batch by signing a transition batch agreement and paying any required fees before the start of the transition batch.
(4) Pre-application reports may not be required for interconnection applications accepted before the effective date of these rules.
(5) If an applicant with an interconnection application that is pending as of the effective date of these rules and that is otherwise eligible to join the transition batch has not submitted a complete and conforming application, an electric utility shall process the incomplete or non-conforming interconnection application according to R 460.936(7)(a) and (b). If the interconnection application is not deemed complete and conforming prior to an electric utility beginning its interconnection studies, the electric utility shall determine whether the interconnection application may be included in the transition batch study.
(6) The interconnection applications in the transition batch must be studied as a group by an electric utility. DERs in the transition batch that are electrically remote may be studied on an expedited schedule, generally in the order the interconnection applications

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were deemed complete, but this expedited scheduling may not cause unreasonable delays in the evaluation of the other DERs in the transition batch.

(7) An electric utility shall process the transition batch and provide facilities study results to interconnection applicants within 6 months of the start date. The start date for the transition batch must be specified in an electric utility's draft interconnection procedures and published on an electric utility's public website within 10 business days of the effective date of these rules.

(8) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in the transition batch. The scoping meetings must meet the following requirements:

(a) All meetings must, to the extent feasible, take place within the first 30 days of the transition batch.

(b) An electric utility shall not begin studies within the transition batch until it has held a scoping meeting with every applicant that had agreed to participate in a meeting. An electric utility may begin the batch study if 1 or more applicants is unreasonably delaying a meeting.

(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.

(d) During the scoping meeting, an electric utility shall identify and communicate to each applicant the studies it plans to perform and provide the cost of the transition batch study using either fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the transition batch throughout the batch study.

(9) The transition batch process must include a system impact study and a facilities study. An electric utility may specify additional studies it may perform on the transition batch in its interconnection procedures.

(10) Electrically coincident DERs within the transition batch are considered to have equal priority with each other.

(11) An electric utility shall comply with R 460.960(1) and (2) when conducting a system impact study. However, applicants with interconnection applications that have had an engineering review completed within the 12 months prior to the effective date of these rules shall not be required to pay for a new system impact study. Applicants with interconnection applications that have had an engineering review completed more than 12 months prior to the effective date of these rules shall not be required to pay for a new system impact study unless the utility determines that a new study is necessary based on changed conditions affecting the proposed point of interconnection and provides this determination with adequate supporting evidence to the applicant in writing.

(12) An electric utility shall comply with R 460.962(1) when conducting a facilities study.

(13) An electric utility shall provide written study results to each applicant at the completion of each study during the transition batch. An electric utility shall offer to hold at least 1 conference call with each transition batch applicant at the completion of each study. An electric utility may choose to group the consultation regarding multiple

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Commented [A1]: Does this mean must not be required? Or does this mean the utility can make you pay for a new study?

projects by 1 applicant and its affiliates into the same conference call. This conference call must provide a summary of outcomes and respond to questions from applicants. Where possible, conferences regarding the study results should be held within 30 business days following completion of the study.

(14) Within 40 business days following completion of the study, an applicant shall choose either to continue in the transition batch or withdraw. The fee for the next study in the transition batch is due by the end of the 40 business day period, unless extended by the electric utility. Applicants that withdraw from the transition batch may reapply with a new interconnection application.

(15) Applicants may reduce the capacity of the DER by up to 20% during the decision period between studies, including up to and through the conclusion of the system impact study. If an applicant wants to increase the capacity of the DER by any amount or decrease the capacity of the DER by more than 20%, an electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

Commented [A2]: We suggest that reductions in capacity should be allowed up to a higher percentage than 20% during the decision period.

(16) Within 45 days of receiving the final transition batch study report, an applicant shall notify the electric utility whether it intends to proceed to an interconnection agreement pursuant to R 460.964 or withdraw. Failure to notify an electric utility within the required time period shall result in the interconnection application being withdrawn.

(17) Under circumstances where an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, other interconnection applications in the transition batch must continue to progress. If feasible, due to the status of the transition batch study, the delayed interconnection application may rejoin the transition batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, may also rejoin the batch study at a later date, if feasible, due to the status of the batch study.

(18) A transition batch study is considered complete 45 business days after all transition batch applicants, except those applicants whose DERs are still causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, have withdrawn, or have received a final transition batch study report.

R 460.920 Electric utility interconnection procedures.

Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms, after input from interested parties, within 30 business days of the effective date of these rules.

Commented [A3]: It is concerning that stakeholders will not have the ability to offer input on the utility procedures until long after they are filed and Staff have reviewed them. It would be beneficial for Staff, the Commission, and the utilities to engage stakeholders formally far sooner in the process and before the procedures are essentially final.

(2) The commission shall issue its order approving, rejecting, or modifying the proposed interconnection procedures and forms within 360 days of the effective date of these rules. If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another party in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

(3) Until the commission accepts, rejects, or modifies an electric utility's interconnection procedures and forms, the electric utility may use the proposed

interconnection procedures and forms when processing interconnection applications with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms.

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, include all of the following:

(a) All necessary applications, forms, and relevant template agreements.

(b) A schedule of all applicable fixed fees and fee caps.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Details regarding methods or standards for power-limited export in compliance with section XXXX.

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

(m) Details describing how an energy storage device may be simply integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.

(o) Examples of modifications that are not material modifications.

(p) The procedure for performing a material modification review.

(6) An electric utility shall obtain formal commission approval to revise its interconnection procedures.

R.XXXX Limited-Export and Non-Exporting Generating Facilities

(1) An electric utility shall allow interconnection of limited-export or non-exporting generating facilities and energy storage according to these procedures.

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Commented [A4]: As described below, we would strongly suggest that the Commission should spell this out more clearly along the lines of the IREC model interconnection standards. This is a huge issue for battery storage systems right now.

Commented [A5]: It is important that this clearly indicate that it is the expectation and the norm that energy storage shall be able to be added to a LNM system easily and simply without impacting the 10-year grandfathering period. There is no incentive for the utilities to make this simple or possible for customers. Given that the Commission would like this to be easily possible for customers, this should be made clear to the utilities.

Commented [A6]: There are no definitions provided of “acceptable material modifications” and “unacceptable material modifications” and in fact, it does not on the face appear to make sense to use these terms. Either a modification is material, and therefore some amount of re-study is necessary, or a modification is not material, and therefore the application can proceed without restudy. The utility should not be able to determine whether an applicant is willing to pay for re-study (thereby making the material modification “acceptable”) or not willing to pay (thereby making the material modification “unacceptable”).

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Commented [A7]: This section is copied from the IREC model interconnection rules (2019) and details the manner in which export can be effectively and safely limited from energy storage facilities. We strongly encourage the Commission to require each utility to include a section modeled on this section to detail specifically and consistently how energy storage can be used. Each utility should reference this rule in their procedures and indicate how they are compliant.

If a Generating Facility uses any configuration or operating mode in this Section, subparagraphs 1 through 6 to limit the export of electrical power across the Point of Common Coupling, then the Generating Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a Generating Facility must comply with the limits in subparagraphs 5 or 6. The Generating Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement. Other means not listed in this Section may be utilized to limit export if mutually agreed upon by the Utility and Applicant.

1. Reverse Power Protection: To ensure power is never exported across the Point of Common Coupling, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.
2. Minimum Power Protection: To ensure at least a minimum amount of power is imported across the Point of Common Coupling at all times (and, therefore, that power is not exported), an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay.
3. Relative Distributed Energy Resource Rating: This option requires the Nameplate Rating of the generating unit, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional Protective Functions is not required to ensure that power will not be exported to the Electric Delivery System. This option requires the generating unit capacity to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months.
4. Configured Power Rating: A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating.

5. Limited Export Utilizing Inverters or Control Systems: Generating Facilities may utilize, a Nationally Recognized Testing Laboratory "NRTL") Certified Power Control System and inverter system that results in the Generating Facility disconnecting from the Electric Delivery System, ceasing to energize the Electric Delivery System or halting energy production within 2 seconds if the period of continuous Inadvertent Export exceeds 30 seconds. Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the Generating Facility entering an operational mode where no energy is exported across the Point of Common Coupling to the Electric Delivery System.

6. Limited Export Using Mutually Agreed-Upon Means: Generating Facilities may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export to levels mutually agreed upon by the Applicant and the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within

mutually agreed-upon limits, the Interconnection Customer shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

R 460.922 Online applications and electronic submission.
Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.
(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:
(a) These rules and interconnection procedures in an electronically searchable format.
(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.
(c) Sample documents including, at a minimum, a 1-line diagram with required labels and minimum safety standards/requirements.
(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.
(e) Directions for the submission of applications.

Commented [A8]: Often these applications require multiple back-and-forth revisions. It would be easier if applicants were fully aware of the requirements placed on each system by the utility.

R 460.924 Communications.
Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process.
(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.
(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Fees.
Rule 26. (1) After the effective date of these rules, fees for the pre-application report, the simplified track, the non-export track, the fast track, and the transition batch fee shall be established as listed in subrule (2) of this rule. Initial fees for the study track shall not exceed initial fee caps as established in subrule (3) and shall remain in effect until interconnection procedures are approved by the commission under R 460.920.
(2) The fixed fee amounts for the pre-application report, the simplified track, the non-export track, and the fast track, for all levels of DERs are as follows:

Commented [A9]: At the very least, the fees for pre-application reports, simplified track, non-export track, fast track, and transition batch fee should be set by the Commission and not set by the utilities in their procedures and then changed at the discretion of the utilities. Michigan EIBC suggests the Commission adopt the same fees charged by nearly all other states with updated interconnection rules. There is no clear reason why Michigan's utilities should have significantly higher costs than other Midwest utilities or, if they do currently have higher costs, why efficiencies could not be determined.

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(a) The pre-application report fee may not exceed $300.
(b) The simplified track fee and any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.
(c) The non-export track fee may not exceed $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.
(d) The fast track initial review fee is $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.
(e) The transition batch fee for interconnection application review and the scoping meeting may not exceed $300.

(3) The initial fee caps, for the study track, for all levels of DERs, are as follows:
(a) The fee for a fast track supplemental review including all review screens may not exceed $1,000.
(b) The study track fee for interconnection application review and the scoping meeting may not exceed $300.
(c) The system impact study fee may not exceed $10,000.
(d) The facilities study fee may not exceed $15,000.
(4) The fixed fees listed in subrule (2) of this rule and the initial fees caps listed in subrule (3) of this rule, and any fixed fees subject to the initial fee caps charged by the electric utility, must be displayed prominently on the electric utility's interconnection website.

R 460.928 Fee and fee cap modifications.
Rule 28.
(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(3)(a), (b), (c) and (d), and any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.
(3) The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.
(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.
(5) The fixed fees and fee caps that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.
(6) Any modification of fees may not be applicable to fees already paid.

R 460.930 Pre-application report request form.
Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.
(2) The pre-application report request form must include all of the following information:

Commented [A10]: It is critical to ensure that these rules create a path forward for DG customers to interconnect to the grid outside of the LNM or DG program (understanding that the caps for those programs may be reached again soon).

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Deleted: (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the initial fee caps specified in R 460.926(2)(a), (b), (c), (d), (e), and (g), and any other fixed fees the electric utility considers necessary. ...

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(a) Project contact information, including name, address, phone number, and email address.
(b) Project location, as accurately as can be identified, which may be given by any of the following:
(i) Street address with nearby cross streets and town.
(ii) An aerial map with location clearly marked.
(iii) GPS coordinates.
(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.
(d) Whether the DER is any of the following:
(i) Solar.
(ii) Wind.
(iii) Cogeneration.
(iv) Storage.
(v) Solar with storage.
(vi) Other type of DER.
(e) Nameplate capacity of the DER types in alternating current kW.
(f) Whether the DER configuration is single or 3-phase.
(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.
(h) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.
(i) Whether the location is new construction.

R 460.932 Pre-application report.
Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.
(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.
(3) The pre-application report must include all of the following information:
(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.
(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.
(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.
(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.
(f) Nominal distribution circuit voltage at the proposed point of common coupling.
(g) Feeder identifier and feeder voltage.
(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.
(h) Approximate circuit distance between the proposed point of common coupling and the substation.
(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.
(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.
(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.
(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.
(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.
(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.
(o) Whether or not the area has been identified as having a prior affected system.
(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available. The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.

(6) An electric utility shall provide the data required in the pre-application report to the applicant within 15 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant.

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R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.

(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:
(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.
(b) An enforceable option to purchase or acquire a leasehold site for this purpose.

(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.
(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature on the application.
(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.
Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.
(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.
(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.
(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.
(5) For interconnection applications with proposed DERs that fall into levels 4 and 5, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.
(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric utility has received the interconnection application, the application attachments, and payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.
(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.
(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the simplified track, non-export track, fast track, or study track.
(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to

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continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.

(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a publicly available interconnection list, which is available in a sortable spreadsheet format. The sortable spreadsheet must be provided it to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.

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(2) The public interconnection list must include all of the following:

(a) An application identifier.

(b) The date that the electric utility received the application.

(c) The date that the electric utility considered the application to be complete and conforming.

(d) Whether the application is on the simplified track, non-export track, fast track, or study track.

(e) The proposed DER nameplate capacity.

(f) The proposed DER interconnection size level.

(g) The DER technology type.

(h) The county and township in which the proposed point of common coupling will be located.

(i) The current status of the application's progress in the interconnection process.

(j) The labels, names, or identifiers of the distribution circuit and substation.

R 460.940 Simplified track review.

Rule 40. (1) Level 1 and 2 applications, including applications that include an energy storage device so the export of power meets the requirements of level 1 or level 2 according to section XXXX, must be processed using the simplified track.

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(2) Within 10 business days after notifying an applicant that the application had been accepted, an electric utility shall perform a review by using up to all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant if any interconnection facilities, distribution upgrades, further study, or

application modifications are required for safe and reliable interconnection to the electric utility's distribution system or for tariff compliance. If an electric utility chooses to perform a review by using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require application modification or further study.

(3) If the utility review notification indicates that no further study or application modifications are required, the applicant shall proceed under R 460.964 to an interconnection agreement.

(4) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business days that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (2) of this rule.

(5) If further study is required, the electric utility and the applicant shall decide whether to proceed to a supplemental review under R 460.950 or the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and to notify the electric utility. In the absence of this notification, the electric utility may withdraw the application.

R 460.942 Non-export track review.

Rule 42. (1) Interconnection applications for DERs that will not inject electric energy into an electric utility's distribution system are eligible for evaluation under the non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility for assistance in determining whether a non-export track review will be sufficient or the study track is necessary. The electric utility shall provide the applicant assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require interconnection facilities, distribution upgrades, further study, or application modifications.

(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install within 10 business days of the applicant being notified. Within 10 business days of receiving the

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equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.

(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business day that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (4) of this rule.

(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.

(6) When an applicant changes from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application.

R 460.944 Fast track applicability.

Rule 44. (1) Applications up to 4MW in nameplate capacity in which the DER is not proposing to interconnect with the electric utility's high voltage distribution system are eligible for the fast track. These applications may include applications that provide for the use of an energy storage device so the export of power is less than 4MW.

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may include additional initial review screens in its interconnection procedures. In its application requesting approval of interconnection

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(3) The electric utility may waive application of 1, some, or all of the initial review screens.

(4) Within 20 business days after an electric utility receives a complete and conforming application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens.

(5) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The electric utility may consider 100% of applicable loading, if available, instead of 15% of line section peak load.

(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's maximum load or 50 kWac.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling.

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers.

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen

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3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the DER's nameplate rating must be less than 250 kWac. This screen does not include substation voltage regulators.

(6) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection agreement must proceed under R 460.962.

(7) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (4) of this rule.

(d) Withdraw the interconnection application.

(8) If the applicant does not select a course of action under subrule (7) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant's request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(7).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(4).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (6) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures so long as those details do not undermine or negate the meaning of the screens.

(2) An electric utility may include additional supplemental review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, the electric utility shall provide a detailed technical rationale for the inclusion of each supplemental review screen. No such additional screen shall negate or undermine any of the supplemental review screens specified in subrule (6) of this rule.

(3) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(4) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(5) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, an electric utility shall perform a supplemental review and notify the applicant

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(6) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (7) and (8) of this rule. All of the following must be applied by the electric utility:

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in subrule (6)(a) of this rule. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section may not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal and emergency ampacity.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(7) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(8) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(9) For subrules (7) and (8) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the simplified track, the non-export track, or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the simplified track or the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted

pursuant to R 460.936, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), (d), or (e) of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(4) An electric utility shall study all interconnection applications that qualify for study track either individually or in a batch study process. An electric utility shall not study 1 or more applications individually and at the same time study 1 or more different applications as part of a batch.

(5) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities impact study fee.

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R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs.

(a) An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility has elected to study all interconnection applications that qualify for study track individually.

(b) An electric utility determined the application to be complete and conforming.

(c) An application qualifies for study track pursuant to R 460.952.

(d) An interconnection application has a pre-application report, when required by R 460.936(2).

(e) An applicant has paid all required fees.

(f) An applicant has signed and returned an individual study agreement.

(5) If an electric utility anticipated that it would use a batch study process but received only 1 interconnection application that qualified for the study track, the electric utility shall consider the first day of what would have been the batch study process to be the day the application was determined to be complete and conforming and shall use the individual study process to evaluate the application with all applicable timelines.

R 460.956 Batch study process.
Rule 56. (1) This rule applies only to those electric utilities that have elected to study DERs that qualify for study track in a batch process.
(2) A batch consists of 2 or more interconnection applications that will be studied as a group by the electric utility. One or more DERs in the batch that are electrically remote may be studied on an expedited schedule, but expedited scheduling of 1 or more DERs may not cause unreasonable delays in the evaluation of the other DERs in the same batch.
(3) An electric utility shall process at least 2 batches per year. The start and end dates for each batch study must be published on the electric utility's public website not less than 60 days prior to the start of the batch.
(4) Interconnection applications that meet all of the following requirements must be admitted into a batch study:
(a) The electric utility elected to study all interconnection applications that qualify for study track in a batch study process.
(b) The electric utility considered the application complete and conforming within a 1-year period immediately before the batch study commences.
(c) The accepted application qualifies for study track pursuant to R 460.952.
(d) The interconnection application has a pre-application report when required by R 460.930(2).
(e) The applicant has paid all required fees including any milestone payments as described in the electric utility's interconnection procedures.
(f) The applicant has signed a batch study agreement.
(5) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in a batch. The scoping meetings and the electric utility must meet all of the following requirements:
(a) All meetings must, to the extent feasible, take place within 30 days of the batch start date.
(b) An electric utility shall not begin studies within a batch until it has held a scoping meeting with every applicant who agreed to participate in a meeting. An electric utility may begin the batch study if an applicant is unreasonably delaying a meeting.
(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.
(d) During the scoping meeting, the electric utility shall identify and communicate to each applicant the studies it plans to perform and estimate the cost of the batch study, using either the fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures.

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Commented [A21]: There should be ways to find efficiencies (e.g., certain processes can be overlapping) to process more than 1 batch per year.

The cost estimate must assume that all applicants will stay in the batch throughout the batch study.

(6) The batch process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. The electric utility may specify additional studies it may perform on a batch study in its interconnection procedures.

(7) Interconnection applications within a batch must be considered to have equal priority with each other.

(8) An electric utility shall follow R 460.960(1) and (2) when conducting a system impact study.

(9) An electric utility shall follow R 460.962(1) when conducting a facilities study.

(10) An electric utility shall provide written study results to each applicant at the completion of each study during the batch study. An electric utility shall offer to hold a conference call with each batch applicant at the completion of each study phase, with the electric utility making reasonable efforts to accommodate applicants' availability when scheduling the call. An electric utility may choose to group the consultation of multiple projects by the applicant and its affiliates into the same conference call. The conference call must provide a summary of outcomes and answer questions from applicant. All conferences regarding the study results should be held within 30 business days following completion of each study phase.

(11) Within 45 business days following the completion of each study phase, the applicant shall choose to either continue to the next study phase of the batch study or withdraw. The fee for the next study phase in the batch study is due by the end of the 45 business days, unless extended by the electric utility. An applicant that withdraws from the study may reapply with a new interconnection application.

(12) Applicants may reduce the capacity of the DER by up to 20% during the decision period between study phases until the conclusion of the system impact study. If the applicant wants to increase the capacity of the DER, the electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

Commented [A22]: We suggest that reductions in capacity should be allowed up to a higher percentage than 20% during the decision period.

(13) Within 45 business days of the applicant receiving the final batch study report from the electric utility, the applicant shall notify the electric utility of its plan to proceed to R 460.964 for an interconnection agreement or withdraw its interconnection application. If the applicant fails to notify the electric utility within 45 business days, the electric utility may withdraw the interconnection application.

(14) If an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, the other interconnection applications in the batch must continue to progress through the batch study process. If feasible, considering the status of the batch study, the delayed interconnection application may rejoin the batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, may rejoin the batch study at a later date, if feasible, considering the status of the batch study.

(15) A batch study is considered complete 45 business days after all batch applicants, except those applicants whose DERs are either causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, pursuing formal mediation

under R 460.906, or pursuing a complaint under R 792.10439 to R 792.10446, have withdrawn, voluntarily or otherwise, or have received the final study results from the electric utility.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to those electric utilities that have elected to individually study DERs that qualify for study track.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.

(4) The scoping meeting may occur in-person or via telecommunications.

(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study, or an interconnection agreement and the basis for that decision, and 1 of the following must occur:

(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.

(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.

(c) If a system impact study is not required and a facilities study is not required, the interconnection application must proceed to R 460.964 for an interconnection agreement.

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Commented [A23]: Given that this is a list of 3 possible outcomes, it is confusing to have (c) say that it "must" proceed to an IA.

R 460.960 System impact study agreement, scope, procedure, and review meeting.

Rule 60. (1) For all DERs being studied individually or as part of a batch, all of the following apply:

(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.

(b) A system impact study agreement must include all of the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.

(iv) A timeline for completion of the system impact study.

(v) A list of the information that must be provided to the applicant in the system impact study report.

(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.

(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.

(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.

(2) For DERs being studied as part of a batch, an electric utility may request reasonable additional data from the applicant during the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the batch study within the 1-year timeframe specified in R 460.956. An electric utility may not be found in violation of these rules when 1 or more applicants impede the batch study process through applicant delays, demands, complaints, litigation, objections, or other similar actions.

(3) For DERs being studied individually, all of the following shall apply:

(a) The electric utility shall complete the system impact study and the system impact study report. If necessary, the electric utility shall transmit a facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data**.**

(b) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subrule (3)(a) of this rule.

(c) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(d) Upon request by the applicant pursuant to subrule (3)(c) of this rule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(e) At the system impact study review meeting, the electric utility shall offer the applicant all of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(iii) Withdraw the interconnection application.

(f) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.
(g) The system impact study review meeting may occur in-person or via telecommunications.

R 460.962 Facilities study agreement, scope, procedure; review meeting.
Rule 62. (1) For DERs being studied individually or as part of a batch, all of the following apply:
(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. If no system impact study was performed, the electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.
(b) The facilities study agreement must include the following:
(i) An outline of the scope of the study.
(ii) The applicable fee.
(iii) A timeline for completion of the facilities study.
(iv) A list of the information that will be provided to the applicant in the facilities study report.
(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.
(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. The electric utility shall provide cost estimates that are detailed and itemized.
(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.
(2) For DERs being studied individually, all of the following are required:
(a) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee.
(b) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:
(i) Request a facilities study review meeting with the electric utility.
(ii) Proceed to an interconnection agreement pursuant to R 460.964.
(iii) Withdraw the interconnection application.
If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.
(c) Upon request by the applicant pursuant to subrule (2)(b)(i) of this rule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be

connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.

(d) At the facilities study review meeting, the electric utility shall offer both of the following options:

(i) Proceed to an interconnection agreement pursuant to R 460.964.

(ii) Withdraw the interconnection application.

(e) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.

(f) The facilities study review meeting may be conducted in-person or via telecommunications.

R 460.964 Interconnection agreement.

Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement to an applicant within 3 business days of reaching this stage.

(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement with modifications to address required construction activities, construction milestone timing, and cost to an applicant within 5 business days of reaching this stage. The applicant and electric utility shall mutually agree on the timing of construction milestones.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the standard level 1, 2, and 3 interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the standard level 1, 2, and 3 interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility did not receive the signed standard level 1, 2, and 3 interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subrule 3(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, the formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the standard level 1, 2, and 3 interconnection agreement within 10 business days of the applicant returning the signed standard level 1, 2, and 3 interconnection agreement.

(5) For level 4 or 5 projects, the electric utility shall provide its level 4 and 5 interconnection agreement within 10 business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the level 4 and 5 interconnection agreement must contain either timelines for completion of activities and estimates of construction costs or a timetable when these requirements can be determined. The interconnection agreement must include a payment schedule that corresponds to the milestones established and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the level 4 and 5 interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility does not receive the signed level 4 and 5 interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subrule (6)(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility's standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting batch studies, if either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment prior to the electric utility beginning the study phase of the next batch study pursuant to R 460.956, the electric utility may not include the interconnection application in the system baseline for conducting the next batch study. If the interconnection application is electrically coincident with other interconnection applications in the next batch study, the electric utility may require the withdrawal of the interconnection application.

(ii) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the

applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant prior to being incurred. The cost may not exceed 125% of the estimate without the consent of the applicant prior to the costs being incurred.

(9) A party's obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:

(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.

(b) Propose the earliest alternate date when it can attain this and future milestones.

(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.

(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:

(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.

(b) The milestone under question has been previously delayed.

(c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.

(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.

(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades.

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute. Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER.

(b) If the applicant's previous aggregate payments exceed its costs under the construction agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations, provided that these modifications do not alter the rights or obligations of the interconnection customer.

Commented [A24]: It seems that this section should clarify that this cannot be done without express commission approval.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. The electric utility's interconnection procedures must describe the technical requirements of these items.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the standard level 1, 2, and 3 interconnection agreement or level 4 and 5 interconnection agreement.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days.

(4) If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within either of the following:

(a) Ten business days of receiving the notification from the applicant pursuant to subrule (2) of this rule, for level 1, 2, and 3 applications.

(b) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to subrule (2) of this rule for level 4 and 5 applications.

(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests.

(a) If the electric utility waives this right, it shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.

(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.

(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.

(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.

(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.

(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report.

(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.

(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.

R 460.968 Authorization required prior to parallel operation.

Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:

(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.

(b) The applicant complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.

(c) The applicant complied with all applicable local, state, and federal requirements.

(d) The electric utility received full payments for all outstanding bills.

(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.

(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.

(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.

R 460.970 Cost allocation of interconnection facilities and distribution upgrades.

Rule 70. The Utility shall describe the methodology for allocating costs to each applicant in the electric utility's interconnection procedures. Each electric utility shall use the methodology for cost allocation as described in sections (1), (2), (3), and (4). If a utility proposes to modify this methodology, the utility must provide justification for doing so.

1) Interconnection Station Upgrades, including all switching stations, shall be allocated based on the number of Generating Facilities interconnecting at an individual station on a per capita basis (i.e. on a per Interconnection Request basis). If multiple Interconnection Customers are connecting to the Utility's System through shared Interconnection Facility(ies), those Interconnection Customers shall be considered one Interconnection Customer for the per capita calculation described in the preceding sentence. Shared Interconnection Facilities shall be allocated based on the number of Generating Facilities sharing that Interconnection Facility on a per capita basis.

2) All Network Upgrades other than those identified in Subsection a shall be allocated based on the proportional impact of each individual Generating Facility in the Cluster Studies on such Network Upgrades. The proportional impact of such Upgrades shall be calculated as follows. All transmission lines and transformers identified as Network Upgrades shall be allocated using distribution factor analysis. Voltage support related Upgrades shall be allocated using a voltage impact analysis which will identify each Generating Facility's contribution to the voltage violation. System Upgrades associated with upgrading existing breakers due to short circuit current exceeding breaker capability shall be allocated proportionally based on the short circuit current contribution of each request.

3) Costs of Distribution Upgrades shall be allocated or assigned to each Interconnection Customer based upon the proportional impact of each individual Generating Facility in the batch study based upon the need for the Distribution Upgrade. Distribution line work (e.g., reconductoring) shall be allocated to Generating Facilities contributing to the Upgrade on a per MW basis, based upon location (% of Upgrade). All other Distribution Upgrades shall be allocated on a per capita basis (i.e. on a per

Interconnection Request basis) based upon the number of projects on the feeder or substation contributing to the need for the Upgrade.

4) Costs of Interconnection Facilities are directly assigned to the Interconnection Customer(s) using such facilities.

R 460.974 Interconnection metering and communications.
Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.
(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.
Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.
(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.
Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:
(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).
(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).
(c) Termination of interconnection by mutual agreement.
(d) Distribution system emergency, but only for the time necessary to resolve the emergency.
(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.
(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.

Commented [A25]: The suggested cost allocation requirements are vague and don't fairly allocate costs to each interconnection applicant.

We would suggest adding in a requirement that a utility use this proposal, which follows procedures in other states, as a starting point – a utility could then modify the proposal in its procedures, but this would provide much clearer guidance to utilities.

Deleted: Costs for interconnection facilities and distribution upgrades must be classified into 1 of the following categories:
(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs. These costs must be assigned to the cost-causing applicant.
(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.
(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.
(h) Other material noncompliance with the interconnection agreement.
(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.
(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

R 460.980 Capacity of the DER.
Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the new nameplate capacity of the DER. The maximum capacity of a DER is the aggregate nameplate capacity or may be limited as described in the electric utility's interconnection procedures.
(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures.
(3) The electric utility's interconnection procedures must describe acceptable methods for power limited export DER including, but not limited to, reverse power protection and utilizing inverters or control systems so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported.

R 460.982 Modification of the interconnection application.
Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform a review to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business days.
(11) Replacing a component with another component that has near-identical characteristics does not constitute a material modification.
(2) The electric utility shall not be required to accept or implement a modification to the electric utility's distribution system or generation assets that is proposed by an applicant or affected system operator.
(3) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.
(4) For a proposed modification which the electric utility has determined is a material modification, the applicant may:

Commented [A26]: We would strongly encourage the Commission to include more information about how this can be done, in a similar manner to the IREC Model Interconnection procedures (as added in section XXXX). It is helpful to have the additional references to export limitation throughout, but more guidance (as is done for the screens) for utility procedures would be very helpful.

Commented [A27]: The flow of this section is now very confusing.

Commented [A28]: "Cursory evaluation" is undefined and unclear. The definition of "material modification" requires a review by the utility and a finding that the modification will affect the system in specific ways. It is unreasonable to deviate from that definition here – both for consistency and to ensure adequate review of modifications.

Deleted: cursory evaluation

Moved (insertion) [1]

Commented [A29]: Rather than having this buried as #11, this should come directly after the requirement for a determination as to whether or not a modification is materials.

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Commented [A30]: As described above, "acceptable material modification" and "unacceptable material modification" are not defined terms. Either a modification is material, and therefore some amount of re-study is necessary, or a modification is not material, and therefore the application can proceed without restudy. The utility should not be able to determine whether an applicant is willing to pay for re-study (thereby making the material modification "acceptable") or not willing to pay (thereby making the material modification "unacceptable"). This section should be revised accordingly.

Deleted: request a material modification review to determine whether the material modification is an acceptable material modification or an unacceptable material modification. The electric utility shall complete the material modification review and determine which of the following options are available to the applicant

(a) withdraw the modification or withdraw the application.
(b) If the modification requires minimal or no restudy, the application study activities will resume with the modification and no change to the timing.
(c) If the modification requires restudy, the electric utility shall expedite the restudy. The applicant shall pay any required fee for the expedited restudy.
(5) The applicant may request a 1-hour consultation to discuss the results of the material modification review.
(6) The applicant shall notify the electric utility of its selection pursuant to subrule (4) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.
(7) If the proposed modification is determined not to be a material modification or is determined to not require restudy, the electric utility shall notify the applicant that the proposed modification has been accepted.
(8) If the modification is considered a material modification, and the applicant disagrees that that determination, the applicant shall withdraw the proposed modification, or initiate mediation pursuant to R 460.904 or R 460.906, or file a complaint pursuant to R 792.10439 to R 792.10446 within 10 business days of receipt of the decision, or proceed with a new interconnection application for this modification. If the applicant does not provide its determination within the 10 business days, the electric utility may consider the interconnection application withdrawn.
(9) Any modification to the interconnection application or to the DER that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.
(10) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.
(12) The electric utility's interconnection procedures must provide examples of modification that are not material modifications, acceptable material modifications, and unacceptable material modifications.
(13) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.
Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant

Deleted: If the modification is an unacceptable material modification, the applicant may

Deleted: is an acceptable material modification and

Commented [A32]: This is undefined and unclear – what does "expedite" mean?

Deleted: is an acceptable material modification but

Deleted: be an acceptable material modification

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Commented [A33]: Again, this doesn't make sense. Either the applicant withdraws it the modification or undergoes study if that is necessary.

Moved up [1]: (11) Replacing a component with another component that has near-identical characteristics does not constitute a material modification.

Commented [A35]: As commented above where this is stated in the procedures section, these designations do not make sense and should not be included.

may not begin any material modification to the DER until the electric utility has accepted the new interconnection application and completed at least one of the following:
(a) An initial review.
(b) A supplemental review.
(c) A system impact study.
(d) A facilities study.

R 460.986 Insurance.
Rule 86. (1) An applicant interconnecting a level 1, 2, or 3 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.
(2) An electric utility shall not require an applicant interconnecting a level 1, 2, or 3 project to name the electric utility as an additional insured party.
(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.
(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.

R 460.988 Easements and rights-of-way.
Rule 88. If an electric utility line extension is required to accommodate an interconnection, the applicant is responsible for procurement and the cost of providing and obtaining easements or rights-of-way.

R 460.990 Interconnection penalties.
Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Catastrophic conditions.
Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to catastrophic conditions as defined in R 460.702(f). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.

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Deleted: (3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000. ¶

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Commented [A36]: From 8/20 draft: EIBC comment: According to my members, in other states, they typically have liability of $2 million for projects greater than 1MW (e.g., 2MW-6MW) (level 5). $3 million in liability is more for much larger projects that would, in Michigan, often not be connecting to the distribution system.

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Commented [A37]: The utility is responsible for procurement and obtaining easements or rights-of-way and the applicant pays the costs of those activities. The applicant cannot be responsible for obtaining rights-of-way/easements. This needs to be clarified.

Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.

Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.

(2) Within 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.

(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.

(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.

(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.

(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.

(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.

(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

Commented [A38]: It is absolutely critical to ensure that these rules create a path forward for DG customers to interconnect to the grid outside of the LNM or DG program (understanding that the caps for those programs may be reached again soon). These rules currently appear to only contemplate access to interconnection through the existing LNM and DG programs – but with the caps rapidly approaching, customers need to have access to interconnection (levels 1, 2, and 3) without needing to also enter one of those programs (e.g., without export, with an energy-only contract, or with a PURPA contract).

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period and into an existing distributed generation program system without impacting participation in the program.

(8) An applicant shall notify the electric utility of plans for any material modification to the project. Except in the case of the addition of energy storage equipment added to an existing system as described in (c), an applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

Commented [A39]: The requirement that an energy storage device cannot export to the distribution system would seem to be counter to Order 2222 and future virtual power plant/aggregation opportunities with storage DERs. This would even be counter to the BYOD programs proposed by Michigan's utilities wherein customer-sited batteries are used to provide grid services.

Deleted: Energy storage devices must be configured to prevent export of stored electricity to the distribution system.

Commented [A41]: We continue to not understand how this can be a material modification and yet not impact the 10 year grandfathering.

Commented [A42]: It's important not only that you don't lose access to the program (i.e., when the caps are hit) by adding an energy storage device.

Commented [A43]: It doesn't make sense to allow an energy storage device to be added but also require a re-application.

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R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on the legacy net metering program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.

(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit the distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to

R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.

(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.

(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.

(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

R 460.1006 Distributed generation program application and fees.

Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the distributed generation program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.

(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:

(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.
(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.
(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.
(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.
(5) If a customer's distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.
(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility's distributed generation program tariff sheet or in the alternative electric supplier's distributed generation program plan.
(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer's interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.
Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173 or the program sizes as determined by legal agreement with the commission or the program sizes as determined voluntarily by an electric utility or alternative electric supplier, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.
(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.
(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.

Commented [A45]: It's important to recognize both that the law may change but also that the caps have been raised in settlement agreements and voluntarily. The Commission still wants notification when those new caps are reached.

(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.

Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.

Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy

in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer's power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer's power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of

measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility.

R 460.1022 Renewable energy credits.

Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.

(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.

(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.

Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.

Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No. U-20890

Introduction

The Michigan Energy Innovation Business Council (Michigan EIBC) appreciates the opportunity to provide comments on the draft Interconnection and Distributed Generation Standards ("draft standards"). We value the Michigan Public Service Commission's ("MPSC" or "Commission") efforts over the last three years to engage stakeholders in a comprehensive process to update Michigan's interconnection standards. Increasing deployment of distributed energy, energy storage, and renewables as well as federal policies such as FERC Order 2222 elevate the importance of setting effective, forward-looking interconnection standards.

Michigan EIBC has been deeply engaged in the development of the draft standards over the last three years and we believe that many aspects of the draft standards represent a significant improvement from the current rules. Specifically, we are strongly supportive of the addition of a pre-application process, simplified track review process for small projects, and fast track process. As detailed below, we have some remaining concerns with the draft standards that we encourage the Commission to address prior to full implementation. Additionally, we are troubled that a number of key decisions are left to utility procedures and that the process to develop those procedures does not include sufficient opportunities for upfront stakeholder engagement.

Overall Comments

Energy storage

Michigan EIBC strongly suggests that the standards should more clearly define processes and procedures around energy storage. With new tariff changes and an increasing focus on reliability and resilience, use of energy storage is growing significantly in Michigan among residential/commercial customers and in conjunction with larger DER projects, and we anticipate increasing interest in distribution-connected storage as well. It is important that the interconnection standards spell out how storage will be treated and evaluated during interconnection screening and study process. The Commission should provide guidance to the utilities to enable the adoption of energy storage and the fair and accurate study of these technologies.

Specifically, the Commission should more clearly spell-out how the utilities shall allow for power-limited export DERs. This is a significant challenge currently with some utilities creating significant roadblocks for behind-the-meter solar plus storage systems with inverter-limited export. We expect this will also be a challenge for front-of-the-meter distribution connected storage. It is important to recognize that export from DC coupled solar plus storage systems is limited by the inverter (and therefore, the total potential output is not the sum of the capacity of the solar system and the storage system). Similarly, in AC coupled systems, energy storage systems will have their own inverters which can limit export capacity. We suggest that the Commission should include specific standards for the utilities to follow as detailed in the 2019 Model Interconnection Rules from IREC. This follows guidance provided by FERC Order 845, which allows an interconnection customer to request service at a lower level than the nameplate generating facility capacity with the proper control technologies in place.

In addition, it is critical in the legacy net metering (“LNM”) and distributed generation (“DG”) section that the addition of energy storage to an existing DG system with these appropriate limited-export controls does not qualify as a material modification and does not result in an applicant being terminated from the LNM or DG program. There could be a requirement that the customer notify the utility that a storage system has been installed, but there should be no need for any re-evaluation or a new interconnection application (i.e., no required re-application) if the appropriate limited-export controls are in place.

Distributed generation standards

It is critical to ensure that these rules create a path forward for DG customers to interconnect to the grid outside of the LNM or DG program (understanding that the caps for those programs may be reached again soon). It is concerning that in the “Interconnection penalties” section, any project less than 100 kW in size is excluded from remedies imposed by the Commission for failure to follow these standards. This seems to imply that projects less than 100 kW in size do not have a right to interconnection outside of the LNM/DG program. These rules currently appear to only contemplate access to interconnection for level 1, 2, and 3 customers through the existing LNM and DG programs – but with the caps rapidly approaching, customers need to have access to interconnection without needing to also enter one of those programs (e.g., without export, with an energy-only contract, or with a PURPA contract).

Batch study process

Michigan EIBC continues to encourage the Commission to carefully consider whether the proposed batch process could be streamlined or improved on. Specifically, we encourage the Commission to review PG&E's interconnection process in California[1] wherein a study track project is first subjected to a two-part Electrical Independence Test (EIT). If the project fails that test, it is then processed through a cluster study process. However, if the project passes the EIT, it can then be studied independently.

Separately, Michigan EIBC continues to encourage the Commission to find ways to speed up the batch study process so that more than one batch can be processed every year. Based on experiences in other states, batch processes can be very problematic. The

[1] See https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/energy-transmission-and-storage/wholesale-generator-interconnection/wholesale-distribution-fast-track-interconnection-process.page?ctx=large-business.

batching process will be useful if it is a process that allows utilities to group projects in a manner that makes sense and decreases personnel, time, and share costs. Otherwise, this process will only serve to increase the time and confusion for applicants.

If a utility processes only one batch per year and then half the projects drop out at the end because it is too expensive to proceed, the utility would have to restudy the remaining projects. That could lead to a two-year delay. For a 6 MW project that was not able to go through fast track, for example, a two-year delay would effectively make it impossible for the project to be built. There should be ways to save time through the process that can allow at least two batches (perhaps with certain time periods overlapping) to occur each year. For example, a utility could start a new batch, do the pre-batch consultations, and retrieve payments before it was done with the last batch. The utility could also start the study process assuming that every project being studied in the last batch will go to completion, which would be the most protective assumption. If that is not an accurate assumption, it would be simple to remove a project that does not go to completion from the study (it is harder to add a project in after the study has started).

Detailed Comments

<u>Part 1. General Provisions</u>

Definitions

- *Definition of material modification:* Michigan EIBC appreciates the addition to the definition of “material modification” that the modification needs to have been reviewed and needs to have been determined to cause a material impact on specific items including cost/timing/design, the distribution system, or safety/reliability. However, we are concerned that the definition of material modification no longer includes a statement indicating that a replacement of a component with a near-identical component does not constitute a material modification. Although this might be reasonably considered to be covered by addition of the list included in the definition, we believe that it would be clearer to additionally include this sentence.

Addition of flowchart: In general, because these rules are new and complex, it would be very helpful for utilities and applicants to have a flowchart available listing all of the processes and timelines. Each utility could be required to include such a flow chart in their procedures or on their website. This would provide significant clarity and greater certainty for applicants -- especially because missing certain deadlines means that an application is deemed withdrawn. The availability of a flowchart would ensure that all applicants are aware of the timelines and requirements at each stage.

<u>Part 2. Interconnection Standards</u>

Legacy applications

Michigan EIBC strongly believes that these rules should allow for valid distribution studies that are older than 6 months (e.g., 12 months old). These interconnection standards have been under development for nearly 3 years and, over that time, there have been many projects that have been unable to move forward beyond a distribution study due to excessive fees or changes to PURPA avoided cost values or other utility-driven challenges with interconnection. In addition, the Covid-19 pandemic has made it difficult for many projects to move forward due to financing, supply chain, and labor issues. As a result, it is unreasonable to require restudy for any project with a distribution study that is older than only 6 months.

If there is a date restriction for distribution studies that qualify for no restudy (e.g., 12 months), Michigan EIBC would also suggest adding a section that would allow projects with older distribution system studies to avoid restudy if the conditions have not significantly changed in that area of the distribution system.

Transition batch

It is important that the transition batch not be the only action that the utility takes for the entire first year that these rules are in place. Although clearing the queue is of great importance, it would be unreasonable to hold up all new applications until the transition batch is created. If possible, the transition batch and the first study batches should be run in tandem or with a shorter offset in timing.

In addition, the start date of the transition batch must be made publicly available as soon as these rules are effective since many applications in the queue will be affected. Given that only Commission Staff will see the first draft of the utility procedures, it is important that the transition batch start date is published on the utility’s public website as soon as possible. We suggest in the concurrently filed redline that this be done within 10 business days of the effective date of the rules.

In a similar manner as above, it is unreasonable to require that engineering reviews must have been completed within 6 months of the effective date of the rules to avoid repetition. Instead, the utility should only be allowed to require a new system impact study if the existing study is more than 12 months old and upon showing cause that a new study is necessary based on changing circumstances affecting the location of interconnection. The language in this section does not make this clear. Specifically, on page 12, “may not be required to pay for a new system impact study” is confusing because “may” could mean “shall not” (as we recommend) or “may depending on the utility’s discretion.”

Finally, we recommend that applicants be allowed to reduce the capacity of the DER by more than 20% during the decision period between studies in the transition batch. It is unclear why this would be limited to 20%, especially if such a change does not impact other projects in the transition batch. There may be a need to decrease the capacity of a DER if the cost for a future study will be greater or if it appears that expensive interconnection upgrades will be required.

Interconnection procedures

It is concerning that both per these draft rules and the timeline set in Case No. U-21117, there appears to be no stakeholder input or engagement on the new utility procedures until at least 3 months after the drafts are filed. We would strongly recommend increased transparency and stakeholder engagement prior to the March and April 2022 stakeholder meetings. In addition, Michigan EIBC is supportive of the draft rule requiring "commission approval" prior to the revision of a utility's procedures but feels the term is relatively vague. We suggest that "formal commission approval" would be more appropriate, necessitating that the utility file a formal proceeding and the Commission act upon such a filing with an official order. We would prefer that stakeholders were given the ability to participate in such a process, but at the very least, it is necessary that any changes to the utility procedures be done in a transparent manner and that approval is not simple approval by Commission Staff without appropriate public input.

In addition, it is important that the Commission clearly indicate that it is the expectation and the norm that energy storage shall be able to be added to a LNM system easily and simply without impacting the 10-year grandfathering period and to a DG system without impacting program participation. There is no incentive for the utilities to make this simple or possible for customers. Given that it appears that the Commission would like this to be easily attainable for customers, this should be made clear to the utilities.

Separately, the draft rules indicate in section (o) (page 14) that the utilities need to provide examples of "modifications that are not material modifications, acceptable material modifications, and unacceptable material modifications." There are no definitions provided of "acceptable material modifications" and "unacceptable material modifications" and in fact, it does not on the face appear to make sense to use these terms. Either a modification is material, and therefore some amount of restudy is necessary, or a modification is not material, and therefore the application can proceed without restudy. The utility should not be able to determine whether an applicant is willing to pay for restudy (thereby making the material modification "acceptable") or not willing to pay (thereby making the material modification "unacceptable").

Fees

At the very least, the fees for pre-application reports, simplified track, non-export track, fast track, and transition batch should be set by the Commission and not set by the utilities in their procedures and then changed at the discretion of the utilities. Michigan EIBC suggests the Commission adopt the same fees charged by nearly all other states that have already updated their interconnection rules as detailed in the Michigan EIBC's concurrently filed redline to the draft standards. There is no clear reason why Michigan's utilities should have significantly higher costs than other Midwest utilities or, if they do currently have higher costs, why efficiencies could not be found to decrease costs. The initial fees for these items, as outlined in the draft rules, are reasonable and should be permanent.

In addition, the fee caps for the study track items outlined in the draft rules are very high compared with similar fees charged in other states. We recommend lowering these initial fee caps with the expectation that most utilities will probably charge the maximum fee caps allowed. These values should not be determined based on a "middle ground" between developers and the utilities – instead, they should be based on best practices from groups like IREC and other states with recently revised rule sets.

Finally, there is no reason that a utility should be allowed to apply for a waiver from the fee caps. These fees for the study track (which are most likely to be costly and variable between projects) will be set by the utility. It is unclear why the Commission would even approve fee caps if it then allows a utility to apply for a waiver from those fee caps whenever the costs exceed the caps.

Pre-application report

Michigan EIBC greatly appreciates the addition of the pre-application report to these standards and appreciates the Commission Staff's attention to this section. We continue to encourage the inclusion of the feeder identifier and feeder voltage in the pre-application report given that these data sets are important to understanding the likely impact of the DER on the grid. In addition, given that the pre-application report only includes readily available data, there is no reason why such reports should take the utility 5 weeks (25 business days) to process. Instead, we suggest that 15 business days should be sufficient.

Fast track

Michigan EIBC believes that eligibility for the fast track should not be limited to level 4 projects. Instead, as suggested by FERC, applicability should be for projects at least up to 4 MW in nameplate capacity. The fast track should be a simple, cost-effective, relatively quick process to determine whether a project can be quickly approved. There is no reason that slightly larger projects should not go through the fast track process in case some of them are able to pass the screens and not cause any issues for the grid or require upgrades.

In addition, it is unclear why the Commission would allow the utility to include additional screens that undermine or negate any of the required screens. Such additional screens, which undermine any of the required screens, simply should not be allowed.

Cost allocation

The cost allocation requirements in the draft standards are vague and do not fairly allocate costs to each interconnection applicant. It is vital that cost allocation is done fairly and consistently, especially because interconnection upgrade costs can be significant and can be notably difficult to allocate given a batch study process. It is also important to ensure that costs attributable to all ratepayers are not assigned to interconnection applicants. We would suggest adding in a requirement that a utility use clear requirements (as outlined in our comments in the draft), based on procedures in other states, as a starting point for the cost allocation methodology included in the utility's procedures. The utility could then modify the proposal in its procedures, but this would provide clearer guidance to utilities.

Modification of an interconnection application

It is important that this section aligns with the definition of "material modification" and with pervious sections in the standards. Specifically, it does not make sense for the utility to do a a “cursory evaluation” to determine if a modification is a material modification given that the definition of material modification requires a review and specific findings.

In addition, as described above, “acceptable material modification” and “unacceptable material modification” are not defined terms. Either a modification is material, and therefore some amount of restudy is necessary, or a modification is not material, and therefore the application can proceed without restudy. The utility should not be able to determine whether an applicant is willing to pay for restudy (thereby making the material modification “acceptable”) or not willing to pay (thereby making the material modification “unacceptable”). This section should be revised accordingly.

Insurance

Throughout this draft, projects sized at levels 1, 2, and 3 are treated in a similar manner (e.g., for fast track review, for the application process, for the study process, etc). These projects also would all potentially be eligible for legacy net metering/the distributed generation program. As such, it does not make sense to require additional insurance for projects less than 150 kW in capacity (level 3). We suggest removing the references to level 3 from the insurance requirements in this section.

In addition, according to Michigan EIBC members, in other states, a liability of $2 million is typically reserved for projects greater than 1MW (e.g., 2MW-6MW; level 5). $3 million in liability is more for much larger projects that would be connected to the transmission system.

Easements and rights-of-way

The utility is responsible for procurement and obtaining easements or rights-of-way and the applicant pays the costs of those activities. The applicant cannot be responsible for obtaining rights-of-way/easements. This needs to be clarified.

<u>Part 3. Distributed Generation Program Standards</u>

Overall Comments

As described above, it is critical to ensure that these rules create a path forward for DG customers to interconnect to the grid outside of the LNM or DG program (understanding that the caps for those programs may be reached again soon).

Application Process

The requirement that an energy storage device cannot export to the distribution system would seem to be counter to Order 2222 and future virtual power plant/aggregation opportunities with storage DERs. This would even be counter to the BYOD programs proposed by Michigan's utilities wherein customer-sited batteries are used to provide grid services. We strongly encourage the deletion of this requirement.

For an existing customer with a signed Interconnection Agreement who would like to add an energy storage device, it needs to be clear both that this customer can do so without losing the 10-year grandfathering in the LNM program and without losing access to the DG program. This will become more critical as we near the caps in the programs because a customer who needs to reapply, as suggested in section (8), may find the DG program closed and then may not only not be able to add their storage device, but also, may be unable to continue to use their existing solar panels.

November 1, 2021

VIA E-Mail to Executive Secretary at mpscedockets@michigan.gov

Dan Scripps, Chair,
Michigan Public Service Commission,
P.O. Box 30221,
Lansing, MI 48909.

RE: Ford Motor Company Comments on Interconnection and Distributed Generation Standards, Case No. U-20890

Dear Mr. Scripps,

Ford intends to take leadership of the electric vehicle revolution by introducing the industry's most compelling high-volume battery electric vehicle lineup and investing more than $30 billion by 2030 to develop connected and electric vehicles and services, including batteries. We're electrifying our most iconic popular models, starting with the F-150 Lightning, the Mach-E and the E-Transit, and customer demand for these vehicles has exceeded our expectations -- we are well positioned to have fully electric vehicles account for 40% to 50% of our U.S. sales by 2030.

Electrification is an important part of our future and to our commitment to reach carbon neutrality no later than 2050, but substantial challenges must be overcome before this future can be realized. We know that adoption of electric vehicles by private customers, commercial and transit operators depends on reliable charging networks. That's why we are so focused on delivering the Blue Oval Charge Network -- the largest public charging network in North America offered by automotive manufacturers -- and technology that improves the customer experience by allowing them to manage and customize their charging needs, route to nearby charging stations, and pay seamlessly all through the FordPass App.

We believe that both public utility and private company participation are needed to fully address these challenges. By working together, we can leverage our unique skillsets and focus, help remove barriers to electrification and address the distinct, varied needs of the EV and charging markets.

To that end, we appreciate the opportunity to provide comments on the proposed revisions to interconnection and generation standards.

1. Electric and Fuel Cell Vehicles should be added explicitly to the list of DERs and Generation sources noted in section R460.930.

2. EVs can potentially qualify as Level 1 or Level 2 sources individually or Level 3+ as an aggregated source such for customers with depot charging capability.

3. Develop a fast track process for EVs seeking interconnection as Level 1 or Level 2. Current fast track (R460.944 -950) is limited to Level 3+ connections only. For special EV interconnection situations where additional study is required, allow the use of the simplified track process (R460.940).

4. Reduce the application and interconnection fees for individual customers or small business entities to a maximum to encourage DER participation.

If you have any questions, please feel free to contact me at jmathew1@ford.com, or at 313 805-4121.

Sincerely,

Jacob Mathews
Manager, EV Charging Strategy and Regulations
Ford Motor Company

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November 1, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20890 – In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned proceeding, please find **Consumers Energy Company's Comments on Proposed Rule Changes.**

This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Ian F. Burgess

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.	))))))	Case No. U-20890

CONSUMERS ENERGY COMPANY'S COMMENTS ON PROPOSED RULE CHANGES

I. INTRODUCTION

On September 9, 2021, the Michigan Public Service Commission ("MPSC" or the "Commission") issued its Order and Notice of Hearing in Case No. U-20890 ("September 9, 2021 Order") regarding the promulgation of the Interconnection and Distributed Generation Standards and the recission of the legacy Electric Interconnection and Net Metering Standards, Mich Admin Code, R.460.601 *et seq*, which were adopted in the May 26, 2009 Order in Case No. U-15787. The September 9, 2021 Order, with the proposed rules attached, scheduled a public hearing for October 20, 2021, to allow presentations by interested persons and set a final deadline for written comments at 5:00 pm on November 1, 2021.

Consumers Energy Company ("Consumers Energy" or the "Company") has participated in ten stakeholder sessions addressing potential Interconnection Rules, and five stakeholder meetings addressing potential Distributed Generation rules, hosted by MPSC Staff between December 2018 and March 2020, as directed by the Commission in its November 8, 2018 Order in Case U-20344. Consumers Energy has provided feedback in response to two draft rule sets in strawman proposals on August 28, 2019, and May 1, 2020, respectively.

The comments presented below are provided by the Company in response to the Commission's September 9, 2021 Order. Consumers Energy appreciates the opportunity to provide further comments on these standards. The proposed rules attached to the September 9, 2021 Order will govern certain electric services provided by the Company; therefore, Consumers Energy has a direct interest in this proceeding. In filing these comments in response to the most recent draft of the proposed Interconnection and Distributed Generation Standards, purusant to the September 9, 2021 Order, Consumers Energy reiterates its positions and recommendations previously expressed in its comments provided as feedback to strawman proposals on August 28, 2019, and May 1, 2020, in addition to the comments presented below.

II. COMMENTS

A. R. 460.964 Interconnection Agreement

Proposed R. 460.964(8) states:

> An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant prior to being incurred. The cost may not exceed 125% of the estimate without the consent of the applicant prior to the costs being incurred.

Consumers Energy submits that R 460.964(8), as presently proposed, is problematic. Interconnection agreements, as currently constructed, do not address requirements that must be satisfied if costs exceed estimates, which could occur due to multiple unforeseen issues, including increased cost of material or labor, unexpected construction conditions (rock, wetland, habitats), cost of right-of-way or rerouting, or design changes. Consumers Energy suggests cost variability be addressed as needed in utility procedures or the utility interconnection agreements themselves and not in the interconnection rules. Additionally, R 460.964(8), as currently proposed, does not include a timeline by which an applicant must respond and provide consent to a utility prior to the cost being incurred. Without including a timeline by which the applicant must respond, it is likely that delays and disputes associated with communcations with applicants to obtain consent will ocurr.

If the Commission preserves the langauge regarding costs exceeding estimates in the proposed rules, the Company proposes that the language below should be adopted to allow for mutually agreed upon mediation, if necessary, without an absolute statement dependent on the consent of only one party.

Consumers Energy Proposed alternate R. 460.964(8):

> An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided at the request of the applicant. If the cost exceeds 125% of the estimate then at the request of the applicant the utility shall provide further explanation on the differences between the cost and the estimate. If informal discussions are unsuccessful, then the parties may mutually agree to request formal mediation per R 460.906.

B. <u>R. 460.988 Easements and right-of-way</u>

The present language in Rule 88 stating the applicant is responsible for procurement of easements or right-of-way is problematic and is opposite from present practice for Interconnection. The utility needs to be responsible for procuring easements or right of way for utility lines it will own, while the applicant is responsible for the cost of providing or obtaining easements or right-of-way.

C. <u>R 460.982 Modification of the interconnection application</u>

The present language in Rule 82 assumes that a material modification request contains all requisite information for the electric utility to perform their review. Consumers Energy currently processes material modifications similar to new application requests involving submittal and review of an application packet. The Company recommends that the interconnection application submittal and review process in Rule 36 be incorporated into this rule.

D. R 460.1006 Distributed generation program application and fees

In R 460.1006 subsection 2a, the proposed rule states that the electric utility "shall complete its review of the distributed generation program application in parallel with processing the interconnection application." Presently, this review is performed sequentially, allowing only conforming applications to proceed to program review. The Company has concern with performing both reviews in parallel due to concerns over needlessly increasing review volume. In the Company's present process, the interconnection application is reviewed for completeness and then sequentially handed off to program review. This allows for only applications with all necessary information to be reviewed for program participation and thus reduces the volume of work in that area. Requiring the reviews to be performed in parallel would require all applications to be reviewed for participation regardless of completeness, which would introduce waste. The Company proposes that the language allow for serial processing of the interconnection and distributed generation program applications.

E. Business days versus calendar days clarifications

The Company noticed a few instances where timeframes were listed in "days" instead of "business days," specifically in R 460.918.8a, R 460.918.16, and R 460.956.5a. As such, the rules as proposed are not exactly clear as to whether the timeframe is based on calendar days or business days. Therefore, the Company recommends that the Commission clarify within the rules that all timeframes be specified in business days.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

COALITION FOR COMMUNITY SOLAR ACCESS

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November 1, 2021

Public comment from the Coalition of Community Solar Access on U-20890

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

On August 6, 2021, the MPSC issued a Notice of Public Hearing regarding draft Interconnection and Distributed Generation Standards that were developed over the course of 10 stakeholder meetings. Following that, on September 9, 2021, the MPSC issued an Order commencing a collaborative to begin the development of the utility-specific electric interconnection procedures that will further guide the transition to renewable energy technology and implement the provisions of Act 342 of 2016.

CCSA is a national coalition of businesses and non-profits working to expand customer choice and access to solar for all American households and businesses through community solar programs. CCSA's mission is to empower every American energy consumer with the option to choose local, clean, and affordable shared solar. CCSA works with customers, utilities, local stakeholders, and key decision makers to develop and implement policies and best practices that ensure community solar programs provide a win, win, win for all, starting with the customer. CCSA members are currently supporting legislation that would unlock the potential for a state-wide community solar program. Members are hopeful that they will be able to bring investment opportunities and economic development to the state in the near future.

Thoughtful, comprehensive interconnection procedures are the foundation to a successful community solar program. CCSA was not able to participate in the stakeholder meetings but we greatly appreciate the time and dedication that went into this public process. Generally speaking, CCSA believes that the large majority of the modifications to the interconnection regulations will generally be very helpful to spur the development of efficient, cost-effective distributed energy resources in the state. For example, CCSA roundly supports the following aspects of the draft regulations:

- Clear project deadlines and a mechanism to remove stalled projects from the queue;
- Clear adoption of technical standards; and
- The inclusion of energy storage in interconnection procedures.

Considering a future in which community solar projects may be built in the state, there are a few major challenges with the draft regulations that will *prohibit* the efficient, cost-effective growth of Distributed Energy Resources (DERs) in Michigan. The primary challenge relates to the utility option to batch study projects on an annual basis. CCSA is not aware of any other state that allows utilities the option to process applications only once per year.

According to CCSA's interpretation of the draft regulations, utilities are likely to use this process for nearly every project over 1 MW. According to the regulations, Fast Track eligibility is limited to 1 MW-ac; projects over 1 MW-ac are considered to be "Study Track" whereby the utilities can choose at their discretion to put them in a "Batch Study Process." The Batch Study process is only required and expected to process **one batch per year** with, as we understand it, an expected **330 day** timeline. The rules contemplate an "Individual Study" but it appears that applicants do not have a guaranteed right to use it. Rule 54 only allows individual study for projects for which "An electric utility has elected to study all interconnection applications that qualify for study track individually." Further, it seems unlikely that a utility would choose to study projects individually because Rule 52.4 states that "An electric utility shall not study 1 or more applications individually and at the same time study 1 or more different applications as part of a batch."

CCSA expects that these rules will lead to every interconnection application above 1MW being forced into an annual batch study process – something usually reserved for much larger systems (typically greater than 5MW; over 20MW in some cases). If this scenario plays out, this process would create sizable delays in project development, allow for significant interconnection uncertainty, and dramatically slow down solar development in Michigan.

As an alternative to this process, CCSA recommends a 5MW cap on Fast Track reviews and a "dual track" model, which has been used successfully in other leading markets. MISO allows for small, qualifying projects, less than 5MW, to be studied quickly and efficiently. For those projects that don't qualify, there should be a dual track interconnection process. Under a dual track system, an independent study happens first and then projects get kicked into a batch study only if they fail an "electrical independence test."

One other somewhat related issue that warrants further consideration is with the project level size categories. Under this draft, the highest category (Level 5) starts at only 1 MW. Most states that have updated their interconnection rules in the last five to ten years have moved toward a structure that is more aligned with FERC and national best practices, or something like the following:

- Level 1: Small certified generating, inverter-based facilities 10 kilowatts (kW) or less;
- Level 2: Certified facilities 2 megawatts (MW) or less;
- Level 3: Non-exporting facilities less than 10MW
- Level 4: Generating facilities 10MW or less that do not qualify for Levels 1-3
- Large (>10MW) Distributed Generation Facilities

As a matter of administrative clarity, CCSA also recommends separating net metering from interconnection regulations as most other states have done. Net metering relates to compensation of DERs, whereas interconnection relates to technical procedures and engineering standards. Creating separate rules for separate concepts makes updating these rules easier and more straightforward, as the DER market evolves over time.

To ensure interconnection rules evolve at the pace of nationally accepted technical standards and practices, CCSA recommends implementing an ongoing interconnection working group as a forum to work through technical and/or policy challenges as they arise. Furthermore, CCSA recommends a planned review of interconnection rules at least every two years.

CCSA greatly appreciates the Commission's attention to updating the state's interconnection procedures to ensure that Michigan can transition to a clean energy economy in a safe, reliable and cost-effective manner. Please do not hesitate to reach out with any questions.

Thank you,

James A Murray
Midwest Regional Director
Coalition for Community Solar Access

My name is Adam Schaller; I am the Vice President of Lakeshore Die Cast and my comments provided below on Case No. U-20890 are based on literature review and my personal experience trying to build and interconnect a distributed energy resource at my die casting company. My die casting company is located in Baroda, Michigan at 8829 Stevensville-Baroda Road in Berrien County. The utility responsible for power supply at my place of business is Indiana Michigan Power, subsidiary of American Electric Power. I've been at Lakeshore Die Cast in a management role since about 2010. In the years between 2010 and 2020 I saw my electricity usage rise by 50% and my price per month more than double. Die casting is an energy intensive business and utilities represent about 10% of my total costs. As a third generation die caster and manufacturer in Michigan, I am always looking for a competitive advantage. I saw how my utility cost increased and started investigating ways to slow down or stymie the increase. This search is what got me interested in on-site generation, particularly solar. In 2020 I installed and connected 150kW AC of generating capacity, the process was straight forward under the old interconnection rules. The latest rule set maintains the previous simplicity for this size of generator which is great. Over the last year my solar project generated about 25% of my total electrical usage and drastically reduced my utility cost. I was so impressed with my solar generation that I started down the path to install more generation. This time around I am working on a 1.25MW system which when combined with my old system will yield 1.4MW AC generation, this is about 2.5 times my current plant yearly demand. I've provided this backstory and information because it helps explain my current situation and why I'm commenting on this case. The new rules don't do anything to address the confusion involved with trying to install solar generation over 150kW in size. The new rules just like old rules say these sized generators must be interconnected and give the rules for interconnecting them. This however is only part of the battle; the other part of the battle is getting the utility to find a tariff that will work and understanding that the utility is required to work with you. I think the new interconnection rule set should explicitly spell out that these sized generators are entitled to net metering as amended in EPACT (Energy Policy Act of 2005) and are qualified facilities as explained in PURPA (Public Utility Regulatory Policies Act). The fact that the old program was called "the net metering program" only adds to the confusion because "the net metering program" is not the same as net metering. My suggestion is that the commission incorporate a section to just explain this or just state what terms a 150kW generating facility that falls outside the distributed generation program are entitled to. These being, net metering as explained in EPACT and sale of power at full avoided cost as clarified in FERC order number 872 and outlined in PURPA.

STATE OF MIGHIGAN

BEFORE THE MIGHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.	))))	Case No. U-20890

Comments of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar

On behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar (collectively, the "Joint Clean Energy Organizations" or "Joint CEOs"), we are pleased to submit these general comments on the on the draft Interconnection and Distributed Generation Standards ("draft standards"). The Joint CEOs have significant experience working on interconnection standards across the United States and engaged in each step leading to these proposed revisions in Michigan: actively participating in workshops, convening and engaging in multiple calls with key stakeholders to negotiate certain points, and providing and explaining proposed redlines to the Interconnection Rules based on our workshop engagement. We now welcome the opportunity to provide comment on the Administrative Rules for Interconnection and Distributed Generation Standards: Rule Set 2020-96 LR.

Comments

The Joint NGOs Comments primary goal in this rulemaking is to ensure that Michigan's Interconnection Rules continue to reflect best practices for the interconnection of distributed energy resources ("DER"). In general, the Joint NGOs commend the Michigan Public Service Commission ("Commission") for initiating the needed update and are supportive of the proposed rule updates. However, there are two general areas in which revisions to the rules as proposed should be revised.

Limited and Non-Exporting Systems

Deployment of a significant amount of energy storage will be absolutely vital to transition Michigan to clean electricity while maintaining system resiliency and reliability. The current Rules, however, do not provide sufficient guidance regarding how energy storage systems (ESS) should be reviewed and evaluated during the interconnection process.

The Commission should more clearly spell-out how the utilities shall allow for limited and non-exporting DERs. This is a significant challenge currently with some utilities creating significant roadblocks for behind-the-meter solar plus storage systems with inverter-limited export.

The defining feature and value of energy storage is its ability to store and discharge energy in the amounts needed and at the time it is needed. This controllability is key to capturing storage systems' benefits (like serving peak load). It is also critical to recognize in the interconnection review process because it can help avoid or mitigate impacts to the distribution system. Thus, interconnection rules should study ESS in a way that takes into account how those systems are actually used instead of assuming incorrectly the export of full Nameplate Capacity at all times.

We strongly suggest that the Commission should include specific standards for the utilities to follow as detailed in the 2019 Model Interconnection Rules from IREC. This follows guidance provided by FERC Order 845, which allows an interconnection customer to request service at a lower level than the nameplate generating facility capacity with the proper control technologies in place.

Utility Procedures

As we have previously discussed in Comments filed in interconnection workshops preceding this rulemaking, the Joint CEOs have concerns with moving too much detail on implementation of the interconnection policies to utility procedures.

Administrative rules provide stability and certainty by providing the agency's written policies that have the effect of law. The Interconnection Rules proposed in this rulemaking provide standards and instructions that impact the ability of customers and independent power producers to exercise their legal rights under Michigan law, the Administrative Procedure Act, and federal laws that are administered and enforced by the agency. The most important policies intended by the Commission for the interconnection process should be included in the rules, not left for incorporation into utility procedures implementing the rules. Utility procedures are not binding on the public and create no legal obligations for utilities or customers. While Joint CEOs recognize the need to balance enforceability with flexibility, in previous comments we have identified specific areas where interconnection standards should be specified in rules rather than as guidelines. We also endorse the proposed changes in this regard proposed by the Michigan Energy Innovation Business Council.

As is evident from the Commission September 26, 2019 Order in Case No. U-20156, a utility's interpretation of Commission language is sometimes inconsistent with Commission interpretation. The Commission has the authority to enforce its rules through official orders. Yet if a utility fails to comply with utility procedures, the Commission may not rely upon utility procedures to support a Commission decision to act or refuse to act.

We recognize and acknowledge that there are many areas in which technology and markets are evolving, so the flexibility to change procedures to accommodate new technology or to enable more rapid adoption of market and technological innovation is a desirable feature of rules. But to the extent possible, we encourage the Commission to adopt rules that set out the general principles of equity, fairness, and customer rights to manage their own energy usage (consistent with safe and reliable operation of the grid).

MICHIGAN BIOMASS

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November 1, 2021

Comment from Michigan Biomass on proposed interconnection rules Case No. U-20890

Michigan Biomass is a coalition of the state's wood-fire power plants supplying Consumers Energy Co. with energy and capacity under existing PURPA power purchase agreements. Following are our comments on proposed interconnection rules under case number U-20890.

Michigan Biomass understands that the proposed interconnection rules in this case are focused on new generation systems expected to connect to the grid because of energy policy that went into effect in April 2017.

There are six biomass plants[1] in Michigan, between 18 MW and 38 MW in size, that have been selling energy and capacity to Consumers Energy under original PURPA contracts signed between 1985 and 1994. All are qualified facilities (QFs) under PURPA.

Michigan Biomass has engaged this rulemaking process since it began in 2018 with Case No. U-20344[2], which initiated the workgroup process to draft strawman proposals for determining what constitutes a Legally Enforceable Obligations (LEO) under PURPA, and to establish revised rules on interconnection standards and processes to conform with actions by the Federal Energy Regulatory Commission.

Throughout that process, and in formal comment under U-20344, members of the Michigan Biomass coalition held concerns that included:

1. Existing facilities, by virtue of their existing agreements and physical interconnections, should not be subject to new interconnection rules intended to manage connection of new generation resources, mainly QFs interconnections such as wind, solar and storage resulting from changes in Michigan energy policy, utility renewable energy objectives, and FERC orders.
2. The potential cost that new rules might bring to existing, interconnected QFs that have limited ability to recover those costs.
3. Consideration of how the rules would impact existing facilities when existing power purchase agreements are renewed or amended.

Throughout this process Michigan Biomass has maintained these existing facility interconnections should be exempt from new rules, and we believe that concern is addressed in section R 460.911 of the proposed rules that defines "applicability:"

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[1] Cadillac Renewable Energy, Grayling Generating Station, Genesee Power Station, Hillman Power Co., Viking Energy/McBain and Viking Energy/Lincoln

[2] *In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection, a legally enforceable obligation, distributed generation, and legacy net metering* (April 8, 2018)

> ***Rule 11.*** *These rules apply to all interconnection applications filed on or after the effective date of these rules and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement. Interconnection applications with a construction agreement or interconnection agreement executed prior to the effective date of these rules are governed by their construction or interconnection agreement.* (Case No. U-20344)

Michigan Biomass supports this language in the proposed rules. In our reading of this section, these rules would not apply to a facility already interconnected because there would be no interconnection application "filed on or before" these rules go into effect, and because these facility interconnections are "governed by" interconnection agreements executed prior to the effective date of these proposed rules.

Sincerely,

Gary Melow, Director

sunrun

November 1, 2021

RE: MPSC Case No. U-20890 - Comments on Draft Interconnection and Distributed Generation Standards

Sunrun is the largest residential solar, storage, and energy management company in the United States with over 500,000 customers in 23 states and the District of Columbia and Puerto Rico. We see great potential to expand solar and storage access more broadly, particularly in the Midwest and especially in Michigan. The need to increase access to reliability solutions like solar and storage is needed now more than ever, with increased weather-related outages and increased interests in improving resiliency for all communities in Michigan.

However, one of the barriers to solar and storage expansion is the lack of clear, transparent, and customer friendly interconnection processes. Michigan can benefit from near term business clarity to support resilient, clean distributed energy resources to provide customer and grid facing services that lower costs in transitioning to clean energy and address needs at the distribution system by alternative means. The customer experience in adopting clean energy technologies is crucial to achieving state and federal policy goals, but in many ways are unfortunately lacking in the interconnection rules as currently proposed.

While Sunrun has not had the opportunity to participate in discussions that led to the most current proposed interconnection rules, we believe it necessary to provide input to support and ensure Michigan transitions to the most modern best practices to enable optimal solar and storage interconnection today and in the future. Sunrun has been active in modernizing interconnection processes and rules change initiatives across the country for solar and storage enablement through the utilization of smart inverters and inverter certified power controls to improve the interconnection experience for the customer and utility. We have proposed limited redline revisions to the rule based on best practices in other states. Additionally, and most importantly, Sunrun believes a second phase of this multi-year effort is needed to most adequately modernize interconnection, distribution planning and utility upgrade process. While the majority of future interconnection customers in Michigan can not cost effectively add storage today, the use of certified power control systems to limit export or the leveraging of advanced grid support functions to avoid upgrades and rapidly streamline interconnection will only come to fruition if utilities are engaged through smart policy decisions. At minimum, the interconnection rule updates must provide real clarity on how inverter power control functions can enable customer savings through more cost effective interconnection. The proposed rules provide no clarity in this regard and fall significantly short in how other jurisdictions have updated rules to provide customer certainty. We respectfully submit the following brief overview of areas we highlight for consideration within the proposed rule redline.

R 460.901a Definitions

The current definitions provide limited clarity in how certified operational controls and the ongoing operating capacity of the distributed energy resource (DER) will be documented within the interconnection agreement, for proper technical assessment within technical screening process, and for documentation of the incremental impact on hosting capacity within distribution planning processes. Customers may utilize operational controls to limit export in order to more cost effectively interconnect and pass technical screens for customer service and distribution system without upgrade or delayed interconnection. Energy storage and certified operational control capabilities of inverters has modernized how DERs interact with the customer and grid, necessitating the need to expand definitions to enable customers adoption and prevent inaccurate technical screening assessment and negative follow through effect on hosting capacity.

R 460.901a UL 1741 Implementation Date

I commend Michigan for striving to adopt the latest version of UL 1741, although the implementation date propoped must be changed in light of the recent release of UL 1741 Edition 3 on September 28, 2021[1]. Initially, California and other forward looking states had planned for an implementation date of January 2022, although it is my understanding that following the release of IEEE 1547.1-2020; the Nationally Recognized Testing Laboratories (NTRL) identified testing challenges, leading to further revisions and creation of UL 1741 Edition 3. Historically, when California and Hawaii have implemented new inverter standards, they have allowed for one year of lead time for enough inverters to be certified for interconnection. The California Smart Inverter Working Group met Oct 28, 2021 to discuss implementation timing, where much uncertainty was raised on the length of time to get inverters certified through NRTLs. UL 1741 SA inverters are used in California, Hawaii, and other states today

[1] https://standardscatalog.ul.com/ProductDetail.aspx?productId=UL1741

allowing for utilization of advanced inverter functions and would be a good candidate for January 2022 implementation, followed by implementation of UL 1741 edition 3 no earlier than January 2023.

Implementation date aside, there are further implementation considerations that Michigan must consider to maximize grid and customer benefit. For example, in Hawaii the original voltage and frequency ride through and trip settings implemented with UL 1741 SA have not changed, but the inverters voltage response settings to local power conditions have evolved. With the implementation of UL 1741 SA new DERs were set with a constant lagging power factor as an approach to limit voltage rise and avoid traditional utility upgrade. Hawaiian Electric's (HECO) research with National Renewable Energy Laboratory (NREL) evolved based on stakeholder input and orders from the Hawaii Public Utilities Commission denying blanket activation of the smart inverters volt-watt function. HECO continued to work with NREL with the focus of avoiding interconnection upgrades without causing excessive customer DER curtailment (volt-watt reduces power output (self-curtailment of energy) as voltage rises negating the need to utility voltage rise assessment and service upgrades for the majority of customers). In rare cases and when utility service infrastructure upgrade is truly needed, customer DER curtailment will increase, reducing the DER customers' operational benefit of the DER. In these cases the utility will come in after the fact and upgrade infrastructure when only truly needed. Consumers are protected from the risk of excessive curtailment, utility infrastructure is maximized, customers more cost effectively interconnection, and we have processes in place today in Hawaii that allow for consumer DER operational protection and instant interconnection for many customers following closure of electrical permits without prior notification to Hawaiian Electric[2].

R 460.946 Fast Track screening processes

The Fast Track process from FERC SGIP has been enhanced by numerous states to better reflect the technical considerations of small inverter based DERs and limited export controls to further streamline the interconnection process. The 15% capacity screen within the initial technical review can be very problematic depending on how utilities administer the interconnection technical screening process, leading to needlessly long and more expensive interconnection processes based on a very conservative threshold. To resolve this, I have proposed additional clarity to this initial

[2] https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21H23A83820D00035

capacity screen based on language specified within the supplemental review screen in order to ensure proper incremental assessment of the DER and proposed a deadline of January 2023 for the utilities to collect and utilize applicable/coincidental minimum loading data within interconnection process. Lack of distribution data can lead to improper assessment of the DERs impact on the distribution and to properly assess the incremental impact of the DER application, the applicable loading data must not be considered as part of the aggregate generation DER that is already reflected within the load data. The National Rural Electric Cooperative Association's PV System Impact Guide in my opinion is a good reference for utilities needing help understanding how to properly use distribution data within technical screening and study processes[3].

Consistent with other jurisdictions that have updated rules for storage and more streamlined interconnection processes, export capacity and the size of the DER should facilitate further technical review streamlining. In my opinion, there is no reason for Level 1 DERs to ever be required to complete a supplemental review process if interconnection is being managed properly.

R 460.980 Capacity of the DER.

While I am unclear why section 460.980 is written specific to interconnection application requests for an increase in capacity for an existing DER, I recommend the language in this section be further clarified and include clear details on how a DER can limit export. I find it confusing to state that the application be based on the new nameplate capacity of the DER. Using nameplate capacity may be appropriate for some DERs, but with customers' adoption of energy storage, the assessment based on nameplate capacity necessitated the need to incorporate additional clarity and details within the interconnection rule to ensure accurate assessments of the DER within technical screening processes. The nameplate capacity of AC coupled storage DERs in particular will lead to wildly inaccurate assessment of the application, which will then carry over within the utilities hosting capacity tracking process to significantly decrease hosting capacity at the customer service and distribution system. States that have updated their interconnection rules have led to the evolution of varying new terms to more clearly explain the basis for DER assessment. In Colorado the term ongoing operating capacity was created and recommended to replace nameplate capacity within the first sentence of section 460.980. In addition allowances for limited and

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3 https://www.cooperative.com/programs-services/bts/Documents/SUNDA/NRECA%20-%20SUNDA%20Impact%20Guide-v3%20final.pdf

non-export must be more clearly expressed within the rule and it may be appropriate to incorporate within section 460.980.

R 460.1001 Application process (Export limitation)

Section 460.1001 specifies a non export use case for energy storage, for which I see no need for. The purpose of interconnection rule update is to allow for a transparent process for proper assessment of the DERs impact on the utility service connect and distribution system. While we must ensure within the rule update that there is sufficient clarity and information for proper utility assessment, we must not limit storage to non export, as this should be a customer choice within the interconnection process.

Sunrun appreciates the opportunity to provide the comments in support of the Commission's goal to modernize Michigan's interconnection rules and we would be happy to discuss our concerns and recommendations, if helpful.

/s/ Steven Rymsha
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Director Grid Solutions, Public Policy
Sunrun Inc.
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DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.914, R 460.916, R 460.918, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.

Rule 1a. As used in these rules:

(a) "AC" means alternating current at 60 Hertz.

(b) "Affected system" means another electric utility's distribution system, a municipal electric utility's distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.

(c) "Affiliate" means that term as defined in R 460.10102(1)(a).

(d) "Alternative electric supplier" means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

(e) "Alternative electric supplier distributed generation program plan" means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(f) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(g) “Applicant” means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.

(h) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(i) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(j) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding the following holidays: New Year’s Day, Martin Luther King Jr. Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Christmas Eve, Christmas Day, and New Year’s Eve. Election Day, the day after Thanksgiving, and any day that meets the criteria of catastrophic conditions as defined in R 460.702(f) may also be excluded.

(k) “Certified” means an inverter-based system has met acceptable safety and reliability standards by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 2020 edition except that prior to January 1, 2022, inverter-based systems which conform to the UL 1741 January 28, 2010 edition are acceptable.

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

(m) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(n) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(o) “Construction agreement” means an agreement, pursuant to the interconnection standards superseded by R 460.901a to R 460.992, between an interconnection customer and an electric utility that contains timelines and cost estimates for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and identifies design, procurement, installation, and construction requirements associated with installation of the DER.

(p) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(q) “DC” means “direct current.”

(r) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of exporting active power to a distribution system.

(s) "Distributed generation program" means the distributed generation program approved by the commission and included in an electric utility's tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(t) "Distribution system" means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(u) "Distribution system study" means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined whether a distribution system upgrade was needed to accommodate the proposed project and the cost of a distribution upgrade if required.

(v) "Distribution upgrades" mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER's connection to the distribution system.

(w) **"**Electric utility" means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, "electric utility" includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) "Electrically coincident" means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

(y) "Electrically remote" means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) "Eligible electric generator" means a methane digester or renewable energy system with a generation capacity limited to a customer's electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) "Energy storage device" means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

(bb) "Engineering review" means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined the suitability of the interconnection equipment including any safety and reliability complications arising from equipment saturation, multiple technologies, and proximity to synchronous motor loads.

(cc) "Facilities study" means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) “Fast track” means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) “Force majeure event” means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause beyond a party’s control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) “Full retail rate” means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

(gg) “Good standing” means an applicant has paid in full all undisputed bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

(hh) “Governmental authority” means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(ii) “GPS” means global positioning system.

(jj) “Grid network” means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer.

(kk) “High voltage distribution” means those parts of a distribution system that operate within a voltage range specified in the electric utility’s interconnection procedures. For purposes of these rules, the term “subtransmission” means the same as high voltage distribution.

(ll) “IEEE” means institute of electrical and electronics engineers.

(mm) “IEEE 1547-2018” means “IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,” as adopted by reference in R 460.902.

(nn) “IEEE 1547.1-2020” means IEEE “Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces,” as adopted by reference in R 460.902.

(oo) “Independent system operator” means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(pp) “Initial review” means the fast track initial review screens described in R 460.946.

(qq) “Interconnection” means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(rr) “Interconnection agreement” means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement shall specify timelines, cost estimates, and payment milestones for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, procurement, installation, and construction requirements associated with installation of the DER. Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.

(ss) "Interconnection coordinator" means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(tt) "Interconnection customer" means the person or entity, which may include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(uu) "Interconnection facilities" mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(vv) "Interconnection procedures" mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) "kW" means kilowatt.

(b) "kWac" means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) "kWh" means kilowatt-hours.

(d) "Legacy net metering program" means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) "Level 1" means a certified project of 20 kWac or less.

(f) "Level 2" means a certified project of greater than 20 kWac and not more than 150 kWac.

(g) "Level 3" means a project of 150 kWac or less that is not certified, or a project greater than 150 kWac and not more than 550 kWac.

(h) "Level 4" means a project of greater than 550 kWac and not more than 1 MWac.

(i) "Level 5" means a project of greater than 1 MWac.

(j) "Level 4 and 5 interconnection agreement" means an interconnection agreement applicable to level 4 and 5 interconnection applications.

(k) "Low voltage distribution" means those parts of a distribution system that operate with a voltage range specified in the electric utility's interconnection procedures.

(l) "Mainline" means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.

(m) “Material modification” means a modification to the DER nameplate rating, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:

(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.

(ii) The cost, timing, or design of any other application.

(iii) The electric utility’s distribution system or an affected system.

(iv) The safety or reliability of the distribution system.

(n) “Methane digester” means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.

(o) “Modified net metering” means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility’s distribution system during a billing period or time-of-use pricing period.

(p) “MW” means megawatt.

(q) “MWac” means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.

(r) “Nameplate capacity” means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation.

(s) “Nameplate rating” means all of the following at which a DER is capable of sustained operation:

(i) Nominal voltage (V).

(ii) Current (A).

(iii) Maximum active power (kWac).

(iv) Apparent power (kVA).

(v) Reactive power (kvar).

(t) “Nationally recognized testing laboratory” means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.

(u) “Network protector” means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs.

(v) “Non-export track” means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility’s distribution system, as described in R 460.942.

(w) “Parallel operation” means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.

(x) “Party” or “parties” means an electric utility, applicant, or interconnection customer.

(y) “Point of common coupling” means the point where the DER connects with the electric utility’s distribution system.

(z) “Radial supply” means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.

(aa) “Readily available” means no creation of data is required, and little or no computation or analysis of data is required.

(bb) “Reasonable efforts” mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.

(cc) “Regional transmission operator” 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, expansion, operation, and use on a regional and interregional basis.

(dd) “Renewable energy credit” means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.

(ee) “Renewable energy resource” means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(ff) “Renewable energy system” means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(gg) “Secondary network” means those areas of a distribution system that operate at a secondary voltage level and are networked.

(hh) “Simplified track” means the procedure for evaluating a level 1 or level 2 proposed interconnection, as described in R 460.940.

(ii) “Site” means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.

(jj) “Spot network” means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.

(kk) “Standard level 1, 2, and 3 interconnection agreement” means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications.

(ll) “Study track” means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.

(mm) “Supplemental review” means the fast track supplemental review screens described in R 460.950.

(nn) “System impact study” means a study to identify and describe the impacts to the electric utility’s distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility’s distribution system. A system impact study also identifies affected systems.

(oo) “Temporary DER” means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.

(pp) “Transition batch” means the group of interconnection applications processed pursuant to R 460.918.

(qq) "True net metering" means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system, during a billing period or time-of-use pricing period.

(rr) "UL" means underwriters laboratory.

(ss) "UL 1741" means the August 3, 2020 revision of "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources," as adopted by reference in R 460.902.

R 460.902 Adoption of standards by reference.

Rule 2. (1) The standards specified in these rules are adopted by reference as follows:

(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, August 3, 2020 revision, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/Catalog.aspx at a cost of $395.00 at the time of adoption of these rules.

(b) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.

(c) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.

(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.

(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.

(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.

(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.

(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.

Rule 4. (1) The parties shall attempt to resolve all disputes arising out of the interconnection process, as defined by R 460.901a through R 460.992, according to the provisions of this rule.

(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties shall discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.

(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.

R 460.906 Formal mediation.

Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party’s possession on which the party intends to rely to support the party’s position.

(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party’s email address and file the notice with the commission.

(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.

(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.

(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.

(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.

(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation or formal mediation pursuant to these rules.

(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Appointment of experts.

Rule 8. (1) If a complaint is filed against an electric utility regarding a technical issue, the commission may, at its discretion, appoint 1 to 3 independent experts to investigate the complaint and report findings to the commission.

(2) The experts shall submit a report to the commission with the results and conclusions of their inquiry and may suggest corrective measures for resolving the complaint. The reports of the experts must be received in evidence and the experts made available for cross examination by the parties at any hearing.

(3) The reasonable expenses of experts appointed pursuant to subrule (1) of this rule, including a reasonable hourly fee or fee determined by the commission, must be submitted by these experts to the commission for approval and, if approved, must be funded under subrule (4) of this rule.

(4) An electric utility or alternative electric supplier shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

R 460.910 Waivers.

Rule 10. An electric utility, customer, alternative electric supplier, applicant, or interconnection customer may apply to the commission for a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.

Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement. Interconnection applications with a construction agreement or interconnection agreement executed prior to the effective date of these rules are governed by their construction or interconnection agreement.

R 460.914 Transition non-study group.

Rule 14. (1) Interconnection applications that were filed before the effective date of these rules and that do not meet the eligibility criteria for transition batch study must be placed into the transition non-study group.

(2) An electric utility shall determine whether an interconnection application in the transition non-study group is eligible to go through the simplified track, non-export track, or fast track within 30 business days of the effective date of these rules. Within 30 business days of making the eligibility determination, an electric utility shall commence processing the interconnection application according to the applicable timelines in these rules.

(3) An electric utility shall process incomplete or non-conforming interconnection applications according to R 460.936(7)(a) and (b).

R 460.916 Legacy applications.

Rule 16. (1) For applicants with interconnection applications that have complete distribution system studies and that have entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection must be completed according to existing contractual arrangements.

(2) For applicants that have distribution system studies which were completed by an electric utility within the 6 months prior to the effective date of these rules, but have not entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection application must proceed to an interconnection agreement under R 460.964.

(3) For applicants that have distribution system studies that were conducted and completed more than 6 months before the effective date of these rules, the electric utility may require a facilities study within the transition batch upon a showing that a new study is necessary based on changed circumstances affecting the location of interconnection.

R 460.918 Transition batch study process.

Rule 18. (1) An electric utility shall begin its transition batch 80 business days after the effective date of these rules.

(2) Interconnection applications are eligible to join the transition batch if all of the following requirements are met:

(a) The application does not qualify for simplified track, non-export track, or fast track.

(b) The application was accepted at any time prior to the start of the transition batch, including prior to the effective date of these rules.

(c) A distribution study on the interconnection application was not completed at any time prior to the effective date of these rules, or a distribution study was completed more than 6 months before the effective date of these rules and an electric utility decided a facilities study was necessary pursuant to R 460.916(3).

(3) An applicant with an eligible interconnection application pursuant to subrule (2) of this rule may join the transition batch by signing a transition batch agreement and paying any required fees before the start of the transition batch.

(4) Pre-application reports may not be required for interconnection applications accepted before the effective date of these rules.

(5) If an applicant with an interconnection application that is pending as of the effective date of these rules and that is otherwise eligible to join the transition batch has not submitted a complete and conforming application, an electric utility shall process the incomplete or non-conforming interconnection application according to R 460.936(7)(a) and (b). If the interconnection application is not deemed complete and conforming prior to an electric utility beginning its interconnection studies, the electric utility shall determine whether the interconnection application may be included in the transition batch study.

(6) The interconnection applications in the transition batch must be studied as a group by an electric utility. DERs in the transition batch that are electrically remote may be studied on an expedited schedule, generally in the order the interconnection applications were deemed complete, but this expedited scheduling may not cause unreasonable delays in the evaluation of the other DERs in the transition batch.

(7) An electric utility shall process the transition batch and provide facilities study results to interconnection applicants within 1 year of the start date. The start date for the transition batch must be specified in an electric utility's draft interconnection procedures and published on an electric utility's public website.

(8) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in the transition batch. The scoping meetings must meet the following requirements:

(a) All meetings must, to the extent feasible, take place within the first 30 days of the transition batch.

(b) An electric utility shall not begin studies within the transition batch until it has held a scoping meeting with every applicant that had agreed to participate in a meeting. An electric utility may begin the batch study if 1 or more applicants is unreasonably delaying a meeting.

(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.

(d) During the scoping meeting, an electric utility shall identify and communicate to each applicant the studies it plans to perform and provide the cost of the transition batch study using either fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the transition batch throughout the batch study.

(9) The transition batch process must include a system impact study and a facilities study. An electric utility may specify additional studies it may perform on the transition batch in its interconnection procedures.

(10) Electrically coincident DERs within the transition batch are considered to have equal priority with each other.

(11) An electric utility shall comply with R 460.960(1) and (2) when conducting a system impact study. However, applicants with interconnection applications that have

had an engineering review completed within the 6 months prior to the effective date of these rules may not be required to pay for a new system impact study.

(12) An electric utility shall comply with R 460.962(1) when conducting a facilities study.

(13) An electric utility shall provide written study results to each applicant at the completion of each study during the transition batch. An electric utility shall offer to hold at least 1 conference call with each transition batch applicant at the completion of each study. An electric utility may choose to group the consultation regarding multiple projects by 1 applicant and its affiliates into the same conference call. This conference call must provide a summary of outcomes and respond to questions from applicants. Where possible, conferences regarding the study results should be held within 30 business days following completion of the study.

(14) Within 40 business days following completion of the study, an applicant shall choose either to continue in the transition batch or withdraw. The fee for the next study in the transition batch is due by the end of the 40 business day period, unless extended by the electric utility. Applicants that withdraw from the transition batch may reapply with a new interconnection application.

(15) Applicants may reduce the capacity of the DER by up to 20% during the decision period between studies, including up to and through the conclusion of the system impact study. If an applicant wants to increase the capacity of the DER by any amount or decrease the capacity of the DER by more than 20%, an electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(16) Within 45 days of receiving the final transition batch study report, an applicant shall notify the electric utility whether it intends to proceed to an interconnection agreement pursuant to R 460.964 or withdraw. Failure to notify an electric utility within the required time period shall result in the interconnection application being withdrawn.

(17) Under circumstances where an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, other interconnection applications in the transition batch must continue to progress. If feasible, due to the status of the transition batch study, the delayed interconnection application may rejoin the transition batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, may also rejoin the batch study at a later date, if feasible, due to the status of the batch study.

(18) A transition batch study is considered complete 45 business days after all transition batch applicants, except those applicants whose DERs are still causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, have withdrawn, or have received a final transition batch study report.

R 460.920 Electric utility interconnection procedures.

Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms within 30 business days of the effective date of these rules.

(2) The commission shall issue its order approving, rejecting, or modifying the proposed interconnection procedures and forms within 360 days of the effective date of these rules. If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another party in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

(3) Until the commission accepts, rejects, or modifies an electric utility's interconnection procedures and forms, the electric utility may use the proposed interconnection procedures and forms when processing interconnection applications with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms.

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, include all of the following:

(a) All necessary applications, forms, and relevant template agreements.

(b) A schedule of all applicable fixed fees and fee caps.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Acceptable methods or standards for power-limited export DERs.

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

(m) Details describing how an energy storage device may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.

(o) Examples of modifications that are not material modifications, acceptable material modifications, and unacceptable material modifications.

(p) The procedure for performing a material modification review.

(6) An electric utility shall obtain commission approval to revise its interconnection procedures.

R 460.922 Online applications and electronic submission.

Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.

(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:

(a) These rules and interconnection procedures in an electronically searchable format.

(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.

(c) Sample documents including, at a minimum, a 1-line diagram with required labels.

(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.

(e) Directions for the submission of applications.

R 460.924 Communications.

Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process.

(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.

(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Initial fees.

Rule 26. (1) After the effective date of these rules, fees for the pre-application report, the simplified track, the non-export track, the fast track, and the study track may not exceed the initial fee caps listed in subrule (2) of this rule, and the caps must remain in effect until interconnection procedures are approved by the commission under R 460.920.

(2) The initial fee amounts for all levels of DERs are as follows:

(a) The pre-application report fee may not exceed $300.

(b) The simplified track fee and any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.

(c) The non-export track fee may not exceed \$100 + \$1/kWac for certified DERs and \$100 + \$2/kWac for non-certified DERs.

(d) The fast track initial review fee is \$100 + \$1/kWac for certified DERs and \$100 + \$2/kWac for non-certified DERs.

(e) The transition batch fee for interconnection application review and the scoping meeting may not exceed \$300.

(f) The fee for a fast track supplemental review including all review screens may not exceed \$5,000.

(g) The study track fee for interconnection application review and the scoping meeting may not exceed \$300.

(h) The system impact study fee may not exceed \$30,000.

(i) The facilities study fee may not exceed \$30,000.

(3) The initial fees caps listed in subrule (2) of this rule, and any fixed fees subject to the initial fee caps charged by the electric utility, must be displayed prominently on the electric utility's interconnection website.

(4) An electric utility that expects to incur costs greater than the initial fee caps listed in subrule (2) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.928 Fee and fee cap modifications.

Rule 28. (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the initial fee caps specified in R 460.926(2)(a), (b), (c), (d), (e), and (g), and any other fixed fees the electric utility considers necessary.

(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(2)(f), (h), and (i), and any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.

(3) The fixed fees must be specific to level size and be based on estimates of reasonable costs to perform the applicable service or study. The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.

(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.

(5) The fixed fees and fee caps that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.

(6) Any modification of fees may not be applicable to fees already paid.

(7) An electric utility that expects to incur costs greater than its prevailing fee caps in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.930 Pre-application report request form.

Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.

(2) The pre-application report request form must include all of the following information:

(a) Project contact information, including name, address, phone number, and email address.

(b) Project location, as accurately as can be identified, which may be given by any of the following:

(i) Street address with nearby cross streets and town.

(ii) An aerial map with location clearly marked.

(iii) GPS coordinates.

(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.

(d) Whether the DER is any of the following:

(i) Solar.

(ii) Wind.

(iii) Cogeneration.

(iv) Storage.

(v) Solar with storage.

(vi) Other type of DER.

(e) Nameplate capacity of the DER types in alternating current kW.

(f) Whether the DER configuration is single or 3-phase.

(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.

(h) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.

(i) Whether the location is new construction.

R 460.932 Pre-application report.

Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.

(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.

(3) The pre-application report must include all of the following information:

(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.

(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.

(f) Nominal distribution circuit voltage at the proposed point of common coupling.

(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.

(h) Approximate circuit distance between the proposed point of common coupling and the substation.

(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.

(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.

(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.

(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.

(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.

(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.

(o) Whether or not the area has been identified as having a prior affected system.

(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available. The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.

(6) An electric utility shall provide the data required in the pre-application report to the applicant within 25 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant.

R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.

(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:

(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.

(b) An enforceable option to purchase or acquire a leasehold site for this purpose.

(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.

(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature on the application.

(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.

Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.

(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.

(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.

(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.

(5) For interconnection applications with proposed DERs that fall into levels 4 and above, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.

(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric utility has received the interconnection application, the application attachments, and payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.

(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.

(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the simplified track, non-export track, fast track, or study track.

(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.

(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a public interconnection list, which is available in a sortable spreadsheet format, and provide it to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.

(2) The public interconnection list must include all of the following: ——

(a) An application identifier.

(b) The date that the electric utility received the application.

(c) The date that the electric utility considered the application to be complete and conforming.

(d) Whether the application is on the simplified track, non-export track, fast track, or study track.

(e) The proposed DER nameplate capacity.

(f) The proposed DER interconnection size level.

(g) The DER technology type.

(h) The county and township in which the proposed point of common coupling will be located.

(i) The current status of the application's progress in the interconnection process.

(j) The labels, names, or identifiers of the distribution circuit and substation.

R 460.940 Simplified track review.

Rule 40. (1) Level 1 and 2 applications, including applications that include an energy storage device so the export of power meets the requirements of level 1 or level 2, must be processed using the simplified track.

(2) Within 10 business days after notifying an applicant that the application had been accepted, an electric utility shall perform a review by using up to all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant if any interconnection facilities, distribution upgrades, further study, or application modifications are required for safe and reliable interconnection to the electric utility's distribution system or for tariff compliance. If an electric utility chooses to perform a review by using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require application modification or further study.

(3) If the utility review notification indicates that no further study or application modifications are required, the applicant shall proceed under R 460.964 to an interconnection agreement.

(4) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business days that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (2) of this rule.

(5) If further study is required, the electric utility and the applicant shall decide whether to proceed to a supplemental review under R 460.950 or the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and to notify the electric utility. In the absence of this notification, the electric utility may withdraw the application.

R 460.942 Non-export track review.

Rule 42. (1) Interconnection applications for DERs that will not inject electric energy into an electric utility's distribution system are eligible for evaluation under the non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

(2) Subject to review and approval by the commission, an electric utility may limit the eligibility of the non-export track in its interconnection procedures based on the characteristics of its distribution system.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility for assistance in determining whether a non-export track review will be sufficient or the study track is necessary.

The electric utility shall provide the applicant assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require interconnection facilities, distribution upgrades, further study, or application modifications.

(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install within 10 business days of the applicant being notified. Within 10 business days of receiving the equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.

(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business day that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (4) of this rule.

(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.

(6) When an applicant changes from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application.

R 460.944 Fast track applicability.

Rule 44. (1) Level 3 and level 4 applications in which the DER is not proposing to interconnect with the electric utility's high voltage distribution system are eligible for the fast track. These level 3 and level 4 applications may include applications that provide for the use of an energy storage device so the export of power meets the requirements of level 3 or level 4.

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may include additional initial review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, an electric utility shall provide a detailed technical rationale for including each additional screen. If an additional screen conflicts with or undermines any of the initial review screens specified in subrule (5) of this rule, the rationale must include an explanation of how it does so.

(3) The electric utility may waive application of 1, some, or all of the initial review screens.

(4) Within 20 business days after an electric utility receives a complete and conforming application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens.

(5) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The electric utility may consider 100% of applicable loading, if available, instead of 15% of line section peak load.

(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's maximum load or 50 kWac.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling.

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers.

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen
3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the

240 volt service of more than 20% of the nameplate rating of the service transformer.

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the DER's nameplate rating must be less than 250 kWac. This screen does not include substation voltage regulators.

(6) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection agreement must proceed under R 460.962.

(7) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (4) of this rule.

(d) Withdraw the interconnection application.

(8) If the applicant does not select a course of action under subrule (7) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant's request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(7).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(4).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (6) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may include additional supplemental review screens in its interconnection procedures. In its application requesting approval of

interconnection procedures, the electric utility shall provide a detailed technical rationale for the inclusion of each supplemental review screen. If an additional screen negates or undermines any of the supplemental review screens specified in subrule (6) of this rule, the rationale must include an explanation of the technical justification for the additional screen.

(3) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(4) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(5) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, an electric utility shall perform a supplemental review and notify the applicant of the results. The supplemental review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a system impact study if the DER passes the applied supplemental review screens.

(6) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (7) and (8) of this rule. All of the following must be applied by the electric utility:

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in subrule (6)(a) of this rule. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section may not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal and emergency ampacity.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(7) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(8) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(9) For subrules (7) and (8) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the simplified track, the non-export track, or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the simplified track or the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted pursuant to R 460.936, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), (d), or (e) of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(4) An electric utility shall study all interconnection applications that qualify for study track either individually or in a batch study process. An electric utility shall not study 1 or more applications individually and at the same time study 1 or more different applications as part of a batch.

(5) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities impact study fee.

R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs.

(a) An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or

both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility has elected to study all interconnection applications that qualify for study track individually.

(b) An electric utility determined the application to be complete and conforming.

(c) An application qualifies for study track pursuant to R 460.952.

(d) An interconnection application has a pre-application report, when required by R 460.936(2).

(e) An applicant has paid all required fees.

(f) An applicant has signed and returned an individual study agreement.

(5) If an electric utility anticipated that it would use a batch study process but received only 1 interconnection application that qualified for the study track, the electric utility shall consider the first day of what would have been the batch study process to be the day the application was determined to be complete and conforming and shall use the individual study process to evaluate the application with all applicable timelines.

R 460.956 Batch study process.

Rule 56. (1) This rule applies only to those electric utilities that have elected to study DERs that qualify for study track in a batch process.

(2) A batch consists of 2 or more interconnection applications that will be studied as a group by the electric utility. One or more DERs in the batch that are electrically remote may be studied on an expedited schedule, but expedited scheduling of 1 or more DERs may not cause unreasonable delays in the evaluation of the other DERs in the same batch.

(3) An electric utility shall process at least 1 batch per year. The start and end dates for each batch study must be published on the electric utility's public website not less than 60 days prior to the start of the batch.

(4) Interconnection applications that meet all of the following requirements must be admitted into a batch study:

(a) The electric utility elected to study all interconnection applications that qualify for study track in a batch study process.

(b) The electric utility considered the application complete and conforming within a 1-year period immediately before the batch study commences.

(c) The accepted application qualifies for study track pursuant to R 460.952.

(d) The interconnection application has a pre-application report when required by R 460.930(2).

(e) The applicant has paid all required fees including any milestone payments as described in the electric utility's interconnection procedures.

(f) The applicant has signed a batch study agreement.

(5) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in a batch. The scoping meetings and the electric utility must meet all of the following requirements:

(a) All meetings must, to the extent feasible, take place within 30 days of the batch start date.

(b) An electric utility shall not begin studies within a batch until it has held a scoping meeting with every applicant who agreed to participate in a meeting. An electric utility may begin the batch study if an applicant is unreasonably delaying a meeting.

(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.

(d) During the scoping meeting, the electric utility shall identify and communicate to each applicant the studies it plans to perform and estimate the cost of the batch study, using either the fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the batch throughout the batch study.

(6) The batch process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. The electric utility may specify additional studies it may perform on a batch study in its interconnection procedures.

(7) Interconnection applications within a batch must be considered to have equal priority with each other.

(8) An electric utility shall follow R 460.960(1) and (2) when conducting a system impact study.

(9) An electric utility shall follow R 460.962(1) when conducting a facilities study.

(10) An electric utility shall provide written study results to each applicant at the completion of each study during the batch study. An electric utility shall offer to hold a conference call with each batch applicant at the completion of each study phase, with the electric utility making reasonable efforts to accommodate applicants' availability when scheduling the call. An electric utility may choose to group the consultation of multiple projects by the applicant and its affiliates into the same conference call. The conference call must provide a summary of outcomes and answer questions from applicant. All conferences regarding the study results should be held within 30 business days following completion of each study phase.

(11) Within 45 business days following the completion of each study phase, the applicant shall choose to either continue to the next study phase of the batch study or withdraw. The fee for the next study phase in the batch study is due by the end of the 45 business days, unless extended by the electric utility. An applicant that withdraws from the study may reapply with a new interconnection application.

(12) Applicants may reduce the capacity of the DER by up to 20% during the decision period between study phases until the conclusion of the system impact study. If the applicant wants to increase the capacity of the DER, the electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(13) Within 45 business days of the applicant receiving the final batch study report from the electric utility, the applicant shall notify the electric utility of its plan to proceed to R 460.964 for an interconnection agreement or withdraw its interconnection application. If the applicant fails to notify the electric utility within 45 business days, the electric utility may withdraw the interconnection application.

(14) If an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, the other interconnection applications in the batch must continue to progress through the batch study process. If feasible, considering the status of the batch study, the delayed interconnection application may rejoin the batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, may rejoin the batch study at a later date, if feasible, considering the status of the batch study.

(15) A batch study is considered complete 45 business days after all batch applicants, except those applicants whose DERs are either causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, pursuing formal mediation under R 460.906, or pursuing a complaint under R 792.10439 to R 792.10446, have withdrawn, voluntarily or otherwise, or have received the final study results from the electric utility.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to those electric utilities that have elected to individually study DERs that qualify for study track.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.

(4) The scoping meeting may occur in-person or via telecommunications.

(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study, or an interconnection agreement and the basis for that decision, and 1 of the following must occur:

(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.

(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.
(c) The interconnection application must proceed to R 460.964 for an interconnection agreement.

R 460.960 System impact study agreement, scope, procedure, and review meeting.
Rule 60. (1) For all DERs being studied individually or as part of a batch, all of the following apply:
(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.
(b) A system impact study agreement must include all of the following:
(i) An outline of the scope of the study.
(ii) The applicable fee.
(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.
(iv) A timeline for completion of the system impact study.
(v) A list of the information that must be provided to the applicant in the system impact study report.
(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.
(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.
(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.
(2) For DERs being studied as part of a batch, an electric utility may request reasonable additional data from the applicant during the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the batch study within the 1-year timeframe specified in R 460.956. An electric utility may not be found in violation of these rules when 1 or more applicants impede the batch study process through applicant delays, demands, complaints, litigation, objections, or other similar actions.
(3) For DERs being studied individually, all of the following shall apply:
(a) The electric utility shall complete the system impact study and the system impact study report. If necessary, the electric utility shall transmit a

facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data**.**

(b) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subrule (3)(a) of this rule.

(c) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(d) Upon request by the applicant pursuant to subrule (3)(c) of this rule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(e) At the system impact study review meeting, the electric utility shall offer the applicant all of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(iii) Withdraw the interconnection application.

(f) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.

(g) The system impact study review meeting may occur in-person or via telecommunications.

R 460.962 Facilities study agreement, scope, procedure; review meeting.

Rule 62. (1) For DERs being studied individually or as part of a batch, all of the following apply:

(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. If no system impact study was performed, the electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.

(b) The facilities study agreement must include the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) A timeline for completion of the facilities study.

(iv) A list of the information that will be provided to the applicant in the facilities study report.

(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.

(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. The electric utility shall provide cost estimates that are detailed and itemized.

(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.

(2) For DERs being studied individually, all of the following are required:

(a) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee.

(b) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:

(i) Request a facilities study review meeting with the electric utility.

(ii) Proceed to an interconnection agreement pursuant to R 460.964.

(iii) Withdraw the interconnection application.

If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.

(c) Upon request by the applicant pursuant to subrule (2)(b)(i) of this rule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.

(d) At the facilities study review meeting, the electric utility shall offer both of the following options:

(i) Proceed to an interconnection agreement pursuant to R 460.964.

(ii) Withdraw the interconnection application.

(e) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.

(f) The facilities study review meeting may be conducted in-person or via telecommunications.

R 460.964 Interconnection agreement.

Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement to an applicant within 3 business days of reaching this stage.

(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement with modifications to address required construction activities, construction milestone timing, and cost to an applicant within 5 business days of reaching this stage. The applicant and electric utility shall mutually agree on the timing of construction milestones.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the standard level 1, 2, and 3 interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the standard level 1, 2, and 3 interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility did not receive the signed standard level 1, 2, and 3 interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subrule 3(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, the formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the standard level 1, 2, and 3 interconnection agreement within 10 business days of the applicant returning the signed standard level 1, 2, and 3 interconnection agreement.

(5) For level 4 or 5 projects, the electric utility shall provide its level 4 and 5 interconnection agreement within 10 business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the level 4 and 5 interconnection agreement must contain either timelines for completion of activities and estimates of construction costs or

a timetable when these requirements can be determined. The interconnection agreement must include a payment schedule that corresponds to the milestones established and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the level 4 and 5 interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility does not receive the signed level 4 and 5 interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subrule (6)(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility's standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting batch studies, if either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment prior to the electric utility beginning the study phase of the next batch study pursuant to R 460.956, the electric utility may not include the interconnection application in the system baseline for conducting the next batch study. If the interconnection application is electrically coincident with other interconnection applications in the next batch study, the electric utility may require the withdrawal of the interconnection application.

(ii) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant prior to being incurred. The cost may not exceed 125% of the estimate without the consent of the applicant prior to the costs being incurred.

(9) A party's obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:

(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.

(b) Propose the earliest alternate date when it can attain this and future milestones.

(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.

(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:

(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.

(b) The milestone under question has been previously delayed.

(c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.

(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.

(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades.

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute. Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER.

(b) If the applicant's previous aggregate payments exceed its costs under the construction agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations, provided that these modifications do not alter the rights or obligations of the interconnection customer.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. The electric utility's interconnection procedures must describe the technical requirements of these items.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the standard level 1, 2, and 3 interconnection agreement or level 4 and 5 interconnection agreement.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days.

(4) If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within either of the following:

(a) Ten business days of receiving the notification from the applicant pursuant to subrule (2) of this rule, for level 1, 2, and 3 applications.

(b) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to subrule (2) of this rule for level 4 and 5 applications.

(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests.

(a) If the electric utility waives this right, it shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.

(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.

(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.

(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.

(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.

(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report.

(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.

(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.

R 460.968 Authorization required prior to parallel operation.

Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:

(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.

(b) The applicant complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.

(c) The applicant complied with all applicable local, state, and federal requirements.

(d) The electric utility received full payments for all outstanding bills.

(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.

(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.

(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.

R 460.970 Cost allocation of interconnection facilities and distribution upgrades.

Rule 70. Costs for interconnection facilities and distribution upgrades must be classified into 1 of the following categories:

(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs. These costs must be assigned to the cost-causing applicant.

(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

R 460.974 Interconnection metering and communications.

Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.

(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.

Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.

(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.

Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:

(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).

(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).

(c) Termination of interconnection by mutual agreement.

(d) Distribution system emergency, but only for the time necessary to resolve the emergency.

(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.

(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.

(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.

(h) Other material noncompliance with the interconnection agreement.

(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.

(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

R 460.980 Capacity of the DER.

Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the new nameplate capacity of the DER. The maximum capacity of a DER is the aggregate nameplate capacity or may be limited as described in the electric utility's interconnection procedures.

(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures.

(3) The electric utility's interconnection procedures must describe acceptable methods for power limited export DER including, but not limited to, reverse power protection and utilizing inverters or control systems so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported.

R 460.982 Modification of the interconnection application.

Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform a cursory evaluation to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business day.

(2) The electric utility shall not be required to accept or implement a modification to the electric utility's distribution system or generation assets that is proposed by an applicant or affected system operator.

(3) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.

(4) For a proposed modification which the electric utility has determined is a material modification, the applicant may request a material modification review to determine whether the material modification is an acceptable material modification or an unacceptable material modification. The electric utility shall complete the material modification review and determine which of the following options are available to the applicant:

(a) If the modification is an unacceptable material modification, the applicant may withdraw the modification or withdraw the application.

(b) If the modification is an acceptable material modification and requires minimal or no restudy, the application study activities will resume with the modification and no change to the timing.

(c) If the modification is an acceptable material modification but requires restudy, the electric utility shall expedite the restudy. The applicant shall pay any required fee for the expedited restudy.

(5) The applicant may request a 1-hour consultation to discuss the results of the material modification review.

(6) The applicant shall notify the electric utility of its selection pursuant to subrule (4) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.

(7) If the proposed modification is determined not to be a material modification or is determined to be an acceptable material modification, the electric utility shall notify the applicant that the proposed modification has been accepted.

(8) If the modification is considered an unacceptable material modification, the applicant shall withdraw the proposed modification, or initiate mediation pursuant to R 460.904 or R 460.906, or file a complaint pursuant to R 792.10439 to R 792.10446 within 10 business days of receipt of the decision, or proceed with a new interconnection application for this modification. If the applicant does not provide its determination within the 10 business days, the electric utility may consider the interconnection application withdrawn.

(9) Any modification to the interconnection application or to the DER that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.

(10) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.

(11) Replacing a component with another component that has near-identical characteristics does not constitute a material modification.

(12) The electric utility's interconnection procedures must provide examples of modification that are not material modifications, acceptable material modifications, and unacceptable material modifications.

(13) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.

Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant may not begin any material modification to the DER until the electric utility has accepted the new interconnection application and completed at least one of the following:

(a) An initial review.

(b) A supplemental review.

(c) A system impact study.

(d) A facilities study.

R 460.986 Insurance.

Rule 86. (1) An applicant interconnecting a level 1 or 2 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.

(2) An electric utility shall not require an applicant interconnecting a level 1 or 2 project to name the electric utility as an additional insured party.

(3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.

(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.

(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $3,000,000.

R 460.988 Easements and rights-of-way.

Rule 88. If an electric utility line extension is required to accommodate an interconnection, the applicant is responsible for procurement and the cost of providing and obtaining easements or rights-of-way.

R 460.990 Interconnection penalties.
Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Catastrophic conditions.
Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to catastrophic conditions as defined in R 460.702(f). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.
Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.
Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.
(2) Within 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.
(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.
(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.

(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.

(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.

(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.

(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. Energy storage devices must be configured to prevent export of stored electricity to the distribution system. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(8) An applicant shall notify the electric utility of plans for any material modification to the project. An applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may

be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application, including any necessary system impact study or facilities study. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on the legacy net metering program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.

(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer's account to permit the distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.

(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative

electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.

(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.

(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

R 460.1006 Distributed generation program application and fees.

Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the distributed generation program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.

(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:

(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility’s notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.

(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application

deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(5) If a customer's distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.

(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility's distributed generation program tariff sheet or in the alternative electric supplier's distributed generation program plan.

(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer's interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.

Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.

(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.

(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.

(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.

Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.

Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer's power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer's power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility.

R 460.1022 Renewable energy credits.
Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.
(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.
(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.
Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.
Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No. U-20890

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby provides comments regarding the proposed administrative rules filed in this docket.

II. COMMENTS

A. Mich Admin Code, R 460.970 (Cost allocation of interconnection facilities and distribution upgrades).

The section that pertains to the allocation of costs for interconnection facilities and distribution upgrades (Mich Admin Code, R 460.970) is important to ensure subsidies between customers are not created. It is not clear from the proposed rules, however, if they apply to both the installation costs and the ongoing operation and maintenance ("O&M") of interconnection facilities and distribution upgrades. This section should be amended to ensure that all costs, including ongoing O&M, are paid by the cost-causing applicants. This is consistent with cost causation principles as well as the statutory requirement that the Commission establish cost of service rates. MCL 460.11(1).

B. Mich Admin Code, R 460.650 and 460.652 (Billing and credit for true/modified net metering customers).

The deletion of a sentence in these rescinded rules is concerning. The sentence that was deleted read, "If a customer leaves the electric utility's distribution system or service is terminated for any reason, an electric utility or alternative electric supplier shall refund to the customer the remaining credit amount." While this issue should be addressed in tariffs, it should also be addressed in the rules. As earned credits belong to the customer, this sentence should be added back to the proposed rules. Without including this requirement in the rules, it is not guaranteed to be adequately addressed elsewhere.

Respectfully submitted,

CLARK HILL PLC

Stephen A. Campbell

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November 1, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.
MPSC Case No. U-20890

Dear Ms. Felice:

Attached for electronic filing in the above-captioned matter is DTE Electric Company's Comments pursuant to the Michigan Public Service Commission's September 9, 2021 Order in Case No. U-20890.

Very truly yours,

Jon P. Christinidis

JPC/erb
Attachments
cc: Service List

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	))))))	Case No. U-20890

COMMENTS OF DTE ELECTRIC COMPANY

Introduction

The Michigan Public Service Commission's ("Commission" or "MPSC") September 9, 2021 Order in Case No. U-20890 (the "Order") invited *"comments, suggestions, data, views, questions, argument, and modifications concerning the issues"* from interested stakeholders regarding the promulgation of the Interconnection and Distributed Generation Standards and the recission of the Electric Interconnection and Net Metering Standards. The order instructed that comments must be received no later than 5:00 p.m. (Eastern time) on November 1, 2021.

DTE ElectricCompany (hereinafter "DTE Electric" or "Company") appreciates the opportunity to provide comments regarding the proposed Interconnection and Distributed Generation Standards which the Commission describes as the "MIXDG rules" (hereinafter the "newly proposed rules") and proposed recission of the Electric Interconnection and Net Metering Standards (hereinafter the "existing rules"). (Order p. 3) In light of the limited time frame to provide comments and the voluminous and complex nature of the newly proposed rules, various higher level procedural, legal and technical "comments," "suggestions," "views" and "modifications" are set forth below. Failure to address each and every issue or provision of the newly proposed rules should not necessarily be construed as agreement by the Company.

Procedural Issues

First, the Company notes that the Commission nearly one (1) year earlier, *prior to providing this opportunity to comment*, made separate Requests for Rulemaking, Regulatory Impact Statements (RIS), etc. and submitted both the newly proposed rules and existing rules for various approvals at other government agencies. Thus, it is unclear what effect, if any, might arise from this comment opportunity. The Company remains hopeful that its continuing concerns will be addressed but emphasizes that DTE Electric has Due Process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right to fair and just treatment in MPSC proceedings: *"No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed."* Michigan Const 1963, art 1, § 17.

Second, the Commission identified several *"stakeholder meetings"* addressing a variety of topics and two (2) opportunities to comment on *"two draft versions of the rules"* – the last opportunity occurring in February 2020, more than 1 ½ years ago. (Order p. 3) Those efforts and opportunities, while not unappreciated, should also not be mistaken for something approaching consensus. For example, while some portions of the newly proposed rules are helpful in requiring interconnection applicants to maintain reasonable progress in pursuing their project, the newly proposed rules also impose unnecessarily complex and prescriptive processes likely to result in confusion, errors, misunderstandings and disagreement.

In addition, the Company notes that the existing rules comprise seventeen (17) pages. The newly proposed rules, at fifty-three (53) pages, are more than three times as long and the

Commission has acknowledged *"the complexity of this rulemaking effort."* (Order p. 3) However, in many respects, that complexity is unnecessary and the rationale for promulgating new rules is not well explained or supported by meaningful facts or data. (See by way of example and not limitation, Order p. 2; Accord RIS p. 6 *"…the process to interconnect customer or developer projects to the utility system can be untimely…"*). Furthermore, by way of example and not limitation, the Regulatory Impact Statement's conclusions that the newly proposed rules are *"expected to streamline the interconnection process," "do not impose a regulatory burden on Commission-regulated electric utilities that is excessive or overly burdensome,"* and *"do not extend beyond what is necessary"* are unpersuasive and unsupported by data. (RIS pp. 6, 7, 8) The vast majority of interconnections to the DTE Electric distribution system are accomplished without significant issue. In fact, the Company has successfully interconnected over 6,000 small generators to its distribution system since the enactment of 2008 PA 295.

Legal Considerations

Several significant legal considerations are implicated by the newly proposed rules. The Administrative Procedures Act provides that:

> *"A rule must not exceed the rulemaking delegation contained in the statute authorizing the rulemaking."* (MCL 24.232(7))

The only specific grants of authority identified by the Commission with respect to the newly proposed rules include MCL 460.10e (addressing generally "merchant plants")[1] and MCL

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[1] Most relevant to the instant rulemaking, MCL 460.10e provides: ***"The commission shall establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations.*** *The standards shall be consistent with generally accepted industry practices and guidelines and shall be established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public.* ***The merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery."*** (MCL 460.10e(3); emphasis added)

460.1173 (addressing generally "distributed generation programs")[2]. MCL 460.10e was enacted more than 20 years ago. Much of what is now MCL 460.1173 has been in place since 2008, although modified in some respects in 2016.

In Consumers Power Co v Public Service Comm, 460 Mich 148, 155-56; 596 NW2d 126 (1999), our Supreme Court explained:

> "The Public Service Commission has no common-law powers. It possesses only that authority granted by the Legislature. Union Carbide v Public Service Comm, 431 Mich 135, at 146, 428 N.W.2d 322. Moreover, this Court strictly construes the statutes which confer power on the PSC. As this Court explained in Union Carbide, supra at 151, 428 N.W.2d 322, quoting Mason Co. Civic Research Council v Mason Co, 343 Mich 313, 326–327, 72 NW2d 292 (1955):
>
> "The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist."

Noncompliance with the APA is reversible error. In re Public Service Commission Guidelines for Transactions Between Affiliates, 252 Mich App 254, 267; 652 NW2d 1 (2002) provided:

> *"Invoking the public interest and the need for policy that is responsive to a changing industry, the PSC eschewed the procedural mandates of the APA in favor of its own course of action . . . While we do not doubt the PSC's legitimate concerns . . . the process utilized by the PSC constituted a rather heavy-handed rebuke of established APA procedures, and, accordingly, we are compelled to invalidate that process" (252 Mich App at 267-68).*

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[2] *As it relates specifically to rulemaking, MCL 460.1173 provides: "**The commission shall establish a distributed generation program by order** issued not later than 90 days after the effective date of the 2016 act that amended this section. **The commission may promulgate rules the commission considers necessary to implement this program. Any rules adopted regarding time limits for approval of parallel operation shall recognize reliability and safety complications including those arising from equipment saturation, use of multiple technologies, and proximity to synchronous motor loads…If necessary to promote reliability or safety, the commission may promulgate rules that require the use of inverters that perform specific automated grid-balancing functions to integrate distributed generation onto the electric grid.*** (MCL 460.1173(1)(5)(b); emphasis added)

The Commission cannot re-write the Legislature's language to include new or different provisions. Hanson v Mecosta Co Rd Comm, 465 Mich 492, 501-503; 638 NW2d 396 (2002). If a Commission order conflicts with a statute, the order is void. Manufacturers Nat'l Bank v DNR, 420 Mich 128, 146; 362 NW2d 572 (1984). Our Supreme Court recently reaffirmed that *"agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature."* In re Complaint of Rovas Against SBC Michigan, 482 Mich 90, 98; 754 NW2d 259 (2008) (Emphasis added).

In light of the thousands of successful interconnections to DTE Electric's and other Michigan electric utilities' distribution systems, relatively static law, and limited *"clear and unmistakable"* direction to promulgate rules there are several instances where it is evident that the newly proposed ruleshave exceeded the Commission's legislative directives.

One example, includes the *retroactive application* of the newly proposed rules, which are implicated, for example, in newly proposed rules R 460.911, R 460.914, R 460.916 and R 460.918. The first of these newly proposed rules makes this intention clear:

> *"These rules apply to all interconnection applications filed on or after the effective date of these rules* ***and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement."*** (R 460.911 Applicability)(emphasis added)

However, there is no *"clear and unmistakable"* statutory authority to promulgate retroactively applicable administrative rules for interconnection or distributed generation.[3] Furthermore, there is a strong presumption against retroactive application of changes in the law

[3] There is also a longstanding prohibition against retroactive ratemaking that confirms the Commission has no such authority with respect to electric utility charges: "[T]he essential principal of the rule against retroactive ratemaking is that when the estimates prove inaccurate and costs are higher or lower than predicted, the previously set rates cannot be changed to correct for the error; the only step that the MPSC can take is to prospectively revise rates in an effort to set more appropriate ones." *The Detroit Edison Co v Public Service Comm*, 416 Mich 510, 523; 331 NW2d 159 (1982) (opinion by Fitzgerald, C.J.).

based on fundamental principles of fairness and predictability. The United States Supreme Court explained, for example:

> "As Justice SCALIA has demonstrated, the presumption against retroactive legislation is deeply rooted in our jurisprudence and embodies a legal doctrine centuries older than our Republic**. Elementary considerations of fairness dictate that individuals should have an opportunity to know what the law is and conform their conduct accordingly; settled expectations should not be lightly disrupted. For this reason, the 'principle that the legal effect of conduct should ordinarily be assessed under the law that existed when the conduct took place has timeless and universal appeal.'** [Kaiser Aluminum & Chemical Corp v Bonjorno, 494 US 827, 855; 110 S Ct 1570; 108 L Ed 2d 842 (1990)] (SCALIA, J., concurring). In a free, dynamic society, creativity in both commercial and artistic endeavors is fostered by a rule of law that gives people confidence about the legal consequences of their actions" (Landgraf v USI Film Products, 511 US 244, 265-66; 114 S Ct 1483; 128 L Ed 2d 229). (1994) (Emphasis added; footnotes omitted).

Michigan Courts have followed Landgraf, recognizing that it would be improper to impose new burdens based on past circumstances, since the affected parties could not avoid the burdens because they already acted (or did nothing) based on the past circumstances. See for example, Frank W. Lynch & Co v Flex Technologies, Inc, 463 Mich 578, 585-87; 624 NW2d 180 (2001); Davis v State Employees' Retirement Bd, 272 Mich App 151, 158; 725 NW2d 56 (2006) (noting Due Process concerns and that: *"A statute may not be applied retroactively if it abrogates or impairs vested rights, creates new obligations, or attaches new disabilities concerning transactions or considerations occurring in the past"*).

Another example includes application of the newly proposed rules to *limit electric utilities' management authority and use of their own property* for their own business purposes – including electric utility-owned generation and distribution systems. Newly proposed rules R 460.901(a)(g) and (tt) as well as R 460.936(8) and (9) relevantly provide:

> *(g) "Applicant" means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility.* ***An electric utility is considered an applicant when it submits an***

> ***interconnection application for a DER that is not a temporary DER.*** (R 460.901(a)(g); emphasis added)
>
> *"(tt) 'Interconnection customer' means the person or entity,* ***which may include the electric utility****, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures."* (R 460.901(a)(tt); emphasis added)
>
> *" (8)* ***An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system****, with the exception of temporary DERs."* (R 460.901(8); emphasis added)
>
> *"(9)* ***An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility****, its subsidiaries or affiliates, or others, with the exception of temporary DERs."* (R 460.936(9); emphasis added)

The bounds of regulation are aptly described in Union Carbide v. Public Service Comm., 431 Mich 135; 428 NW2d 322 (1988)

> *"The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. 'It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership.' [citations omitted]".*

It is clear that the Commission is an economic regulator and not the operator of DTE Electric or its various facilities and there is no relevant administrative rulemaking authority to the contrary. Ford Motor Co. v. Public Service Comm, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) *("The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best."*); Consumers Power Co, Public Service Comm, 189 Mich App 151, 180; 472 NW2d 77 (1991) *("To the extent that the PSC* *actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority"*).[4]

A third concern involves the newly proposed rules determination to utilize *"fee caps" for actions and studies required by the rules* (See, for example, R 460.920, R460.292, and R 460.928) as well as *requirements to disclose through, inter alia a "Pre-application report", various proprietary and commercially valuable electric utility system information to 3rd parties for only a nominal fee ($300)* and despite the possibility it could be sensitive Critical Electric Infrastructure Information (CEII) (See, for example, R460.926 and R 460.932). *The Company cannot be required to provide services without full compensation nor relinquish its property rights in proprietary business information (including but not limited to electrical system information) without just compensation.* While the newly proposed rules permit *"waiver"* requests for *"an electric utility that expects to incur costs greater than the initial fee caps"* (See R 460.926(4)) the best potential outcome (assuming for the sake of discussion that appropriate relief from the Commission is eventually received) will be initial underpayment by developers with electric utilities left to seek collection of the actual costs from those developers. Furthermore, these mandated disclosures in no way address the market value of the information itself, which the newly proposed rules command be disclosed to other businesses with no compensation whatsoever for the commercial

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[4] Consistent with Consumers, neither is there any apparent authority to require *"standard level 1, 2, and 3 interconnection agreements"*. (See, for example R 460.901b(kk) and R 460.964) The Commission is an *"administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments."* Union Carbide v Public Service Comm, 431 Mich 135, 146; 428 NW2d 322 (1988); Sparta Foundry Co v Public Utilities Comm, 275 Mich 562, 564; 267 NW 736 (1936). The Commission's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. Mason Co Civil Research Council v Mason Co, 343 Mich 313, 326-27; 72 NW2d 292 (1955). The Commission cannot expand its jurisdiction through its own acts or assumption of authority. Ram Broadcasting v Public Service Comm, 113 Mich App 79, 92; 317 NW2d 295 (1982). The Commission cannot re-write the Legislature's language to include new or different provisions.[4] Hanson v Mecosta Co Rd Comm, 465 Mich 492, 501-503; 638 NW2d 396 (2002). If a Commission order conflicts with a statute, the order is void. Manufacturers Nat'l Bank v DNR, 420 Mich 128, 146; 362 NW2d 572 (1984)

value of that information. At a minimum, these "fee caps" and mandated proprietary and commercially valuable electric utility information disclosures risk violation of the requirement that *"[t]he merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery."* (MCL 460.10e(3); Accord MCL 460.1175(1) *"The customer shall pay all interconnection costs."*)

However, in addition, DTE Electric has constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the US Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, the Michigan Constitution of 1963, art 10, § 2 provides in part, *"Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law."*[5]

Yet another overarching Due Process concern involves the complex dispute resolution procedures set forth in the newly proposed rules which provide for "Informal Mediation", "Formal Mediation", "Appointment of Experts", "Contested Cases" and "Complaints." (See generally R 460.904, R 460.906, and R 460.908) Informal Mediation places Commission Staff in what appears to be the role of mediator. (See R 460.904(3)) Subsequent to any Informal Mediation, Formal

[5] These constitutional protections have been recognized and applied to public utility rates in well-established case law. See generally, Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); Federal Power Comm v Natural Gas Pipeline, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); Duquesne Light Co v Barasch, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). See also, Northern Michigan Water Co v Public Service Comm, 381 Mich 340; 161 NW2d 584 (1968); Consumers Power Co v Public Service Comm, 415 Mich 134; 327 NW2d 875 (1982); ABATE v Public Service Comm, 430 Mich 33; 420 NW2d 81 (1988).Furthermore, as a matter of fundamental ratemaking law, DTE Electric and other electric utilities are entitled to a commensurate return of and on their investment in providing utility service. *See, Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). *See also, Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

Mediation appears to be required.[6] Formal Mediation requires multiple submissions to the Commission and involves an Administrative Law Judge (ALJ) as mediator with *"assistance from commission staff."* (R 460.906(1)(a)-(f)) And the newly proposed rules also appear to preserve the potential filing of a *"contested case proceeding"* pursuant to the Rules of Practice and Procedure Before the Commission (See generally, R 792.10401 et. seq.; See specific reference in newly proposed rule R 460.906(1)(f) to R 792.10415 "General Provisions" addressing a "contested case proceeding"). The newly proposed rules, however, also appear to preserve the right to file a complaint (addressed generally in R 792.10439 – R792.10446 of the Rules of Practice and Procedure Before the Commission) and when a complaint is filed the Commission may engage experts at the expense of the utility[7] to *"investigate the complaint and report findings to the Commission"* and *"[t]he reports of the experts must be received in evidence and the experts made available for cross examination by the parties."* (See R 460.908) It is unclear on whose behalf these experts would testify and how, procedurally, cross examination might work to ensure Due Process. It is also worthy of note that Staff has historically participated in contested cases and complaints[8] as a party, so it is unclear under the newly proposed rules how Staff would reconcile its roles as mediator, provider of *"assistance"* to an ALJ mediator, and potential contested case party. Thus, the newly proposed rules contemplate the potential for at least four (4) forms of addressing disputes that are not mutually exclusive, lack clear adherence to the Administrative Procedures Act MCL 24.201 et. seq., and otherwise do not clearly ensure adequate Due Process.

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[6] "*(1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904,* ***the parties shall then attempt to resolve the dispute*** *in the following manner:…"* (R 460.906(1))(emphasis added)

[7] Here again, there is no provision in the newly proposed rules for an electric utility to recover the cost of providing such experts. See generally MCL 460.10e(3), Michigan Constitution of 1963, art 10, § 2, and the line of cases following Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri cited supra.

[8] A "complaint" *is* also a "contested case" but a "contested case" may not also be a "complaint."

DTE Electric and others have Due Process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right to fair and just treatment in MPSC proceedings: *"No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed."* Michigan Const 1963, art 1, § 17. In addition, In re Public Service Commission Guidelines for Transactions Between Affiliates, 252 Mich App 254, 267; 652 NW2d 1 (2002) confirms that adherence to the Administrative Procedures Act is critical:

> *"Invoking the public interest and the need for policy that is responsive to a changing industry, the PSC eschewed the procedural mandates of the APA in favor of its own course of action . . . While we do not doubt the PSC's legitimate concerns . . . the process utilized by the PSC constituted a rather heavy-handed rebuke of established APA procedures, and, accordingly, we are compelled to invalidate that process" (252 Mich App at 267-68).*

At bottom, there are several significant overarching legal considerations (in addition to more specific concerns found throughout the details of the 53-pages of newly proposed rules) that must be addressed and remediated prior to formal adoption of a final rule on these topics.

Technical Comments and Modifications

In light of the complexity of the newly proposed rules and the limited time available to comment, the Company also wishes to highlight certain technical issues it has identified in the newly proposed rules which is accomplished in attached comments to the newly proposed rules submitted with these narrative comments (Attachment A).

Respectfully Submitted,

DTE ELECTRIC COMPANY

DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.914, R 460.916, R 460.918, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.

Rule 1a. As used in these rules:

(a) “AC” means alternating current at 60 Hertz.

(b) “Affected system” means another electric utility’s distribution system, a municipal electric utility’s distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.

(c) “Affiliate” means that term as defined in R 460.10102(1)(a).

(d) “Alternative electric supplier” means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

(e) “Alternative electric supplier distributed generation program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(f) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(g) “Applicant” means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.

(h) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(i) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(j) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding the following holidays: New Year’s Day, Martin Luther King Jr. Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Christmas Eve, Christmas Day, and New Year’s Eve. Election Day, the day after Thanksgiving, and any day that meets the criteria of catastrophic conditions as defined in R 460.702(f) may also be excluded.

(k) “Certified” means an inverter-based system has met acceptable safety and reliability standards by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 2020 edition except that prior to January 1, 2022, inverter-based systems which conform to the UL 1741 January 28, 2010 edition are acceptable.

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

(m) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(n) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(o) “Construction agreement” means an agreement, pursuant to the interconnection standards superseded by R 460.901a to R 460.992, between an interconnection customer and an electric utility that contains timelines and cost estimates for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and identifies design, procurement, installation, and construction requirements associated with installation of the DER.

(p) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(q) “DC” means “direct current.”

(r) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of exporting active power to a distribution system.

Commented [DTEE1]: This list does not include some utility holidays where planned work is not conducted. These rules should include such days in “business days” and the utility should clearly define the list of business day exclusions in procedures.

Commented [DTEE2]: These rules should make clear that the utility’s highest priority should always be providing ordinary electric service to its customers.

(s) “Distributed generation program” means the distributed generation program approved by the commission and included in an electric utility’s tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(t) “Distribution system” means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(u) “Distribution system study” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined whether a distribution system upgrade was needed to accommodate the proposed project and the cost of a distribution upgrade if required.

(v) “Distribution upgrades” mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER’s connection to the distribution system.

(w) **“**Electric utility” means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, “electric utility” includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) “Electrically coincident” means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

Commented [DTEE3]: There could be both distribution or DER site upgrades that may be required.

(y) “Electrically remote” means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) “Eligible electric generator” means a methane digester or renewable energy system with a generation capacity limited to a customer’s electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) “Energy storage device” means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

(bb) “Engineering review” means a study, conducted under the interconnection standards superseded by R 460.901a to R 460.992, that determined the suitability of the interconnection equipment including any safety and reliability complications arising from equipment saturation, multiple technologies, and proximity to synchronous motor loads.

(cc) “Facilities study” means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) “Fast track” means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) “Force majeure event” means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause beyond a party's control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) "Full retail rate" means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

(gg) "Good standing" means an applicant has paid in full all undisputed bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

Commented [DTEE4]: Customers should be required to pay all bills in a timely fashion, subject to refund.

(hh) "Governmental authority" means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(ii) "GPS" means global positioning system.

(jj) "Grid network" means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer.

(kk) "High voltage distribution" means those parts of a distribution system that operate within a voltage range specified in the electric utility's interconnection procedures. For purposes of these rules, the term "subtransmission" means the same as high voltage distribution.

(ll) "IEEE" means institute of electrical and electronics engineers.

(mm) "IEEE 1547-2018" means "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as adopted by reference in R 460.902.

(nn) "IEEE 1547.1-2020" means IEEE "Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces," as adopted by reference in R 460.902.

(oo) "Independent system operator" means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(pp) "Initial review" means the fast track initial review screens described in R 460.946.

(qq) "Interconnection" means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(rr) "Interconnection agreement" means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement shall specify timelines, cost estimates, and payment milestones for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, procurement, installation, and construction requirements associated with installation of the DER.

Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.

(ss) “Interconnection coordinator” means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(tt) “Interconnection customer” means the person or entity, which may include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(uu) “Interconnection facilities” mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(vv) “Interconnection procedures” mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) “kW” means kilowatt.

(b) “kWac” means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) “kWh” means kilowatt-hours.

(d) “Legacy net metering program” means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) “Level 1” means a certified project of 20 kWac or less.

(f) “Level 2” means a certified project of greater than 20 kWac and not more than 150 kWac.

(g) “Level 3” means a project of 150 kWac or less that is not certified, or a project greater than 150 kWac and not more than 550 kWac.

(h) “Level 4” means a project of greater than 550 kWac and not more than 1 MWac.

(i) “Level 5” means a project of greater than 1 MWac.

(j) “Level 4 and 5 interconnection agreement” means an interconnection agreement applicable to level 4 and 5 interconnection applications.

(k) “Low voltage distribution” means those parts of a distribution system that operate with a voltage range specified in the electric utility’s interconnection procedures.

(l) “Mainline” means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.

(m) “Material modification” means a modification to the DER nameplate rating, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:

(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.
(ii) The cost, timing, or design of any other application.
(iii) The electric utility's distribution system or an affected system.
(iv) The safety or reliability of the distribution system.
(n) "Methane digester" means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.
(o) "Modified net metering" means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system during a billing period or time-of-use pricing period.
(p) "MW" means megawatt.
(q) "MWac" means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.
(r) "Nameplate capacity" means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation.
(s) "Nameplate rating" means all of the following at which a DER is capable of sustained operation:
(i) Nominal voltage (V).
(ii) Current (A).
(iii) Maximum active power (kWac).
(iv) Apparent power (kVA).
(v) Reactive power (kvar).
(t) "Nationally recognized testing laboratory" means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.
(u) "Network protector" means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs.
(v) "Non-export track" means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility's distribution system, as described in R 460.942.
(w) "Parallel operation" means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.
(x) "Party" or "parties" means an electric utility, applicant, or interconnection customer.
(y) "Point of common coupling" means the point where the DER connects with the electric utility's distribution system.
(z) "Radial supply" means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.
(aa) "Readily available" means no creation of data is required, and little or no computation or analysis of data is required.
(bb) "Reasonable efforts" mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.

(cc) "Regional transmission operator" 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, expansion, operation, and use on a regional and interregional basis.

(dd) "Renewable energy credit" means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.

(ee) "Renewable energy resource" means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(ff) "Renewable energy system" means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(gg) "Secondary network" means those areas of a distribution system that operate at a secondary voltage level and are networked.

(hh) "Simplified track" means the procedure for evaluating a level 1 or level 2 proposed interconnection, as described in R 460.940.

(ii) "Site" means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.

(jj) "Spot network" means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.

(kk) "Standard level 1, 2, and 3 interconnection agreement" means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications.

(ll) "Study track" means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.

(mm) "Supplemental review" means the fast track supplemental review screens described in R 460.950.

(nn) "System impact study" means a study to identify and describe the impacts to the electric utility's distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility's distribution system. A system impact study also identifies affected systems.

(oo) "Temporary DER" means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.

(pp) "Transition batch" means the group of interconnection applications processed pursuant to R 460.918.

(qq) "True net metering" means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system, during a billing period or time-of-use pricing period.

(rr) "UL" means underwriters laboratory.

(ss) "UL 1741" means the August 3, 2020 revision of "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources," as adopted by reference in R 460.902.

Commented [DTEE5]: Revision has been superseded to align with 1547.1-2020 and CA rule 21 requirements.

R 460.902 Adoption of standards by reference.
Rule 2. (1) The standards specified in these rules are adopted by reference as follows:
(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, August 3, 2020 revision, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/Catalog.aspx at a cost of $395.00 at the time of adoption of these rules.

Commented [DTEE6]: Revision has been superseded to align with 1547.1-2020 and CA rule 21 requirements.

(b) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.
(c) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.
(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.
(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.
(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.
(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.
(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.
Rule 4. (1) The parties shall attempt to resolve all disputes arising out of the interconnection process, as defined by R 460.901a through R 460.992, according to the provisions of this rule.
(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.
(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties shall discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.

(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.

R 460.906 Formal mediation.

Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party's possession on which the party intends to rely to support the party's position.

(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party's email address and file the notice with the commission.

(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.

(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.

(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.

(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.

(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation or formal mediation pursuant to these rules.

(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Appointment of experts.

Rule 8. (1) If a complaint is filed against an electric utility regarding a technical issue, the commission may, at its discretion, appoint 1 to 3 independent experts to investigate the complaint and report findings to the commission.

(2) The experts shall submit a report to the commission with the results and conclusions of their inquiry and may suggest corrective measures for resolving the complaint. The reports of the experts must be received in evidence and the experts made available for cross examination by the parties at any hearing.
(3) The reasonable expenses of experts appointed pursuant to subrule (1) of this rule, including a reasonable hourly fee or fee determined by the commission, must be submitted by these experts to the commission for approval and, if approved, must be funded under subrule (4) of this rule.
(4) An electric utility or alternative electric supplier shall reimburse the experts appointed by the commission for the reasonable expenses incurred in the course of investigating the complaint.

R 460.910 Waivers.
Rule 10. An electric utility, customer, alternative electric supplier, applicant, or interconnection customer may apply to the commission for a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.
Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules and interconnection applications filed prior to the effective date of these rules that do not have an executed construction or interconnection agreement. Interconnection applications with a construction agreement or interconnection agreement executed prior to the effective date of these rules are governed by their construction or interconnection agreement.

R 460.914 Transition non-study group.
Rule 14. (1) Interconnection applications that were filed before the effective date of these rules and that do not meet the eligibility criteria for transition batch study must be placed into the transition non-study group.
(2) An electric utility shall determine whether an interconnection application in the transition non-study group is eligible to go through the simplified track, non-export track, or fast track within 30 business days of the effective date of these rules. Within 30 business days of making the eligibility determination, an electric utility shall commence processing the interconnection application according to the applicable timelines in these rules.
(3) An electric utility shall process incomplete or non-conforming interconnection applications according to R 460.936(7)(a) and (b).

R 460.916 Legacy applications.

Rule 16. (1) For applicants with interconnection applications that have complete distribution system studies and that have entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection must be completed according to existing contractual arrangements.

(2) For applicants that have distribution system studies which were completed by an electric utility within the 6 months prior to the effective date of these rules, but have not entered into a construction or interconnection agreement with an electric utility as of the effective date of these rules, the interconnection application must proceed to an interconnection agreement under R 460.964.

(3) For applicants that have distribution system studies that were conducted and completed more than 6 months before the effective date of these rules, the electric utility may require a facilities study within the transition batch upon a showing that a new study is necessary based on changed circumstances affecting the location of interconnection.

R 460.918 Transition batch study process.

Rule 18. (1) An electric utility shall begin its transition batch 80 business days after the effective date of these rules.

(2) Interconnection applications are eligible to join the transition batch if all of the following requirements are met:

(a) The application does not qualify for simplified track, non-export track, or fast track.

(b) The application was accepted at any time prior to the start of the transition batch, including prior to the effective date of these rules.

(c) A distribution study on the interconnection application was not completed at any time prior to the effective date of these rules, or a distribution study was completed more than 6 months before the effective date of these rules and an electric utility decided a facilities study was necessary pursuant to R 460.916(3).

(3) An applicant with an eligible interconnection application pursuant to subrule (2) of this rule may join the transition batch by signing a transition batch agreement and paying any required fees before the start of the transition batch.

(4) Pre-application reports may not be required for interconnection applications accepted before the effective date of these rules.

(5) If an applicant with an interconnection application that is pending as of the effective date of these rules and that is otherwise eligible to join the transition batch has not submitted a complete and conforming application, an electric utility shall process the incomplete or non-conforming interconnection application according to R 460.936(7)(a) and (b). If the interconnection application is not deemed complete and conforming prior to an electric utility beginning its interconnection studies, the electric utility shall determine whether the interconnection application may be included in the transition batch study.

(6) The interconnection applications in the transition batch must be studied as a group by an electric utility. DERs in the transition batch that are electrically remote may be studied on an expedited schedule, generally in the order the interconnection applications were deemed complete, but this expedited scheduling may not cause unreasonable delays in the evaluation of the other DERs in the transition batch.

(7) An electric utility shall process the transition batch and provide facilities study results to interconnection applicants within 1 year of the start date. The start date for the transition batch must be specified in an electric utility's draft interconnection procedures and published on an electric utility's public website.

(8) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in the transition batch. The scoping meetings must meet the following requirements:

(a) All meetings must, to the extent feasible, take place within the first 30 days of the transition batch.

(b) An electric utility shall not begin studies within the transition batch until it has held a scoping meeting with every applicant that had agreed to participate in a meeting. An electric utility may begin the batch study if 1 or more applicants is unreasonably delaying a meeting.

(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.

(d) During the scoping meeting, an electric utility shall identify and communicate to each applicant the studies it plans to perform and provide the cost of the transition batch study using either fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the transition batch throughout the batch study.

(9) The transition batch process must include a system impact study and a facilities study. An electric utility may specify additional studies it may perform on the transition batch in its interconnection procedures.

(10) Electrically coincident DERs within the transition batch are considered to have equal priority with each other.

(11) An electric utility shall comply with R 460.960(1) and (2) when conducting a system impact study. However, applicants with interconnection applications that have had an engineering review completed within the 6 months prior to the effective date of these rules may not be required to pay for a new system impact study.

(12) An electric utility shall comply with R 460.962(1) when conducting a facilities study.

(13) An electric utility shall provide written study results to each applicant at the completion of each study during the transition batch. An electric utility shall offer to hold at least 1 conference call with each transition batch applicant at the completion of each study. An electric utility may choose to group the consultation regarding multiple projects by 1 applicant and its affiliates into the same conference call. This conference call must provide a summary of outcomes and respond to questions from applicants. Where possible, conferences regarding the study results should be held within 30 business days following completion of the study.

(14) Within 40 business days following completion of the study, an applicant shall choose either to continue in the transition batch or withdraw. The fee for the next study in the transition batch is due by the end of the 40 business day period, unless extended by

the electric utility. Applicants that withdraw from the transition batch may reapply with a new interconnection application.

(15) Applicants may reduce the capacity of the DER by up to 20% during the decision period between studies, including up to and through the conclusion of the system impact study. If an applicant wants to increase the capacity of the DER by any amount or decrease the capacity of the DER by more than 20%, an electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(16) Within 45 days of receiving the final transition batch study report, an applicant shall notify the electric utility whether it intends to proceed to an interconnection agreement pursuant to R 460.964 or withdraw. Failure to notify an electric utility within the required time period shall result in the interconnection application being withdrawn.

(17) Under circumstances where an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, other interconnection applications in the transition batch must continue to progress. If feasible, due to the status of the transition batch study, the delayed interconnection application may rejoin the transition batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, may also rejoin the batch study at a later date, if feasible, due to the status of the batch study.

(18) A transition batch study is considered complete 45 business days after all transition batch applicants, except those applicants whose DERs are still causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint, have withdrawn, or have received a final transition batch study report.

R 460.920 Electric utility interconnection procedures.

Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms within 30 business days of the effective date of these rules.

(2) The commission shall issue its order approving, rejecting, or modifying the proposed interconnection procedures and forms within 360 days of the effective date of these rules. If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another party in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

(3) Until the commission accepts, rejects, or modifies an electric utility's interconnection procedures and forms, the electric utility may use the proposed interconnection procedures and forms when processing interconnection applications with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms.

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, include all of the following:

(a) All necessary applications, forms, and relevant template agreements.

(b) A schedule of all applicable fixed fees and fee caps.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Acceptable methods or standards for power-limited export DERs.

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

(m) Details describing how an energy storage device may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.

(o) Examples of modifications that are not material modifications, acceptable material modifications, and unacceptable material modifications.

(p) The procedure for performing a material modification review.

(6) An electric utility shall obtain commission approval to revise its interconnection procedures.

R 460.922 Online applications and electronic submission.

Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.

(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:

(a) These rules and interconnection procedures in an electronically searchable format.

(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.

(c) Sample documents including, at a minimum, a 1-line diagram with required labels.

(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.

(e) Directions for the submission of applications.

R 460.924 Communications.

Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process.

(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.

(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Initial fees.

Rule 26. (1) After the effective date of these rules, fees for the pre-application report, the simplified track, the non-export track, the fast track, and the study track may not exceed the initial fee caps listed in subrule (2) of this rule, and the caps must remain in effect until interconnection procedures are approved by the commission under R 460.920.

(2) The initial fee amounts for all levels of DERs are as follows:

(a) The pre-application report fee may not exceed $300.

(b) The simplified track fee and any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.

(c) The non-export track fee may not exceed $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(d) The fast track initial review fee is $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(e) The transition batch fee for interconnection application review and the scoping meeting may not exceed $300.

(f) The fee for a fast track supplemental review including all review screens may not exceed $5,000.

(g) The study track fee for interconnection application review and the scoping meeting may not exceed $300.

(h) The system impact study fee may not exceed $30,000.

(i) The facilities study fee may not exceed $30,000.

(3) The initial fees caps listed in subrule (2) of this rule, and any fixed fees subject to the initial fee caps charged by the electric utility, must be displayed prominently on the electric utility's interconnection website.

(4) An electric utility that expects to incur costs greater than the initial fee caps listed in subrule (2) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.928 Fee and fee cap modifications.

Rule 28. (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the initial fee caps specified in R 460.926(2)(a), (b), (c), (d), (e), and (g), and any other fixed fees the electric utility considers necessary.

(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(2)(f), (h), and (i), and any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.

(3) The fixed fees must be specific to level size and be based on estimates of reasonable costs to perform the applicable service or study. The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.

(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.

(5) The fixed fees and fee caps that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.

(6) Any modification of fees may not be applicable to fees already paid.

(7) An electric utility that expects to incur costs greater than its prevailing fee caps in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.930 Pre-application report request form.

Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.

(2) The pre-application report request form must include all of the following information:

(a) Project contact information, including name, address, phone number, and email address.

(b) Project location, as accurately as can be identified, which may be given by any of the following:

(i) Street address with nearby cross streets and town.

(ii) An aerial map with location clearly marked.

(iii) GPS coordinates.

(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.

(d) Whether the DER is any of the following:

(i) Solar.

(ii) Wind.

(iii) Cogeneration.

(iv) Storage.

(v) Solar with storage.

(vi) Other type of DER.

Commented [DTEE7]: Should specify if the proposed equipment will be certified or non-certified to help determine interconnection level.

(e) Nameplate capacity of the DER types in alternating current kW.

Commented [DTEE8]: KVA, DC KW and KWH of storage if applicable to the proposed project.

(f) Whether the DER configuration is single or 3-phase.

(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.

(h) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.

(i) Whether the location is new construction.

R 460.932 Pre-application report.

Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.

(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.

(3) The pre-application report must include all of the following information:

(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.

(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.

(f) Nominal distribution circuit voltage at the proposed point of common coupling.

(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.

(h) Approximate circuit distance between the proposed point of common coupling and the substation.

(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.

(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.

(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.

(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.

(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.

(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.

(o) Whether or not the area has been identified as having a prior affected system.

(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available. The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.

(6) An electric utility shall provide the data required in the pre-application report to the applicant within 25 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant.

R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.

(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:

(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.

(b) An enforceable option to purchase or acquire a leasehold site for this purpose.

(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.

(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature on the application.

Commented [DTEE9]: Most applications are filled by installer and not customer, so the documentation should include Site owner printed name, Phone number, and email address.

(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.

Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.

(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.

(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.

(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.

(5) For interconnection applications with proposed DERs that fall into levels 4 and above, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.

(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric utility has received the interconnection application, the application attachments, and payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.

(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.

(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the simplified track, non-export track, fast track, or study track.

(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.

(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a public interconnection list, which is available in a sortable spreadsheet format, and provide it to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.
(2) The public interconnection list must include all of the following:
(a) An application identifier.
(b) The date that the electric utility received the application.
(c) The date that the electric utility considered the application to be complete and conforming.
(d) Whether the application is on the simplified track, non-export track, fast track, or study track.
(e) The proposed DER nameplate capacity.
(f) The proposed DER interconnection size level.
(g) The DER technology type.
(h) The county and township in which the proposed point of common coupling will be located.
(i) The current status of the application's progress in the interconnection process.
(j) The labels, names, or identifiers of the distribution circuit and substation.

R 460.940 Simplified track review.
Rule 40. (1) Level 1 and 2 applications, including applications that include an energy storage device so the export of power meets the requirements of level 1 or level 2, must be processed using the simplified track.
(2) Within 10 business days after notifying an applicant that the application had been accepted, an electric utility shall perform a review by using up to all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant if any interconnection facilities, distribution upgrades, further study, or application modifications are required for safe and reliable interconnection to the electric utility's distribution system or for tariff compliance. If an electric utility chooses to perform a review by using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require application modification or further study.
(3) If the utility review notification indicates that no further study or application modifications are required, the applicant shall proceed under R 460.964 to an interconnection agreement.
(4) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business days that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility

may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (2) of this rule.

(5) If further study is required, the electric utility and the applicant shall decide whether to proceed to a supplemental review under R 460.950 or the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and to notify the electric utility. In the absence of this notification, the electric utility may withdraw the application.

R 460.942 Non-export track review.

Rule 42. (1) Interconnection applications for DERs that will not inject electric energy into an electric utility's distribution system are eligible for evaluation under the non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

Commented [DTEE10]: Non-export track available based on agreement to install utility approved controls.

(2) Subject to review and approval by the commission, an electric utility may limit the eligibility of the non-export track in its interconnection procedures based on the characteristics of its distribution system.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility for assistance in determining whether a non-export track review will be sufficient or the study track is necessary. The electric utility shall provide the applicant assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require interconnection facilities, distribution upgrades, further study, or application modifications.

(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install within 10 business days of the applicant being notified. Within 10 business days of receiving the equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.

Commented [DTEE11]: This may require site walkdowns to identify appropriate locations for disconnects, metering and other equipment for tariff compliance in the customer facility. Should be an option for a mutually agreed schedule to determine the specifics of what is needed to proceed.

(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business day that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in this subrule.

(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.

(6) When an applicant changes from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application.

Commented [DTEE12]: Additionally, the customer desire to change rates may bring about tariff specific metering and monitoring requirements for their facility interconnection.

R 460.944 Fast track applicability.

Rule 44. (1) Level 3 and level 4 applications in which the DER is not proposing to interconnect with the electric utility's high voltage distribution system are eligible for the fast track. These level 3 and level 4 applications may include applications that provide for the use of an energy storage device so the export of power meets the requirements of level 3 or level 4.

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may include additional initial review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, an electric utility shall provide a detailed technical rationale for including each additional screen. If an additional screen conflicts with or undermines any of the initial review screens specified in subrule (5) of this rule, the rationale must include an explanation of how it does so.

(3) The electric utility may waive application of 1, some, or all of the initial review screens.

(4) Within 20 business days after an electric utility receives a complete and conforming application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (3) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens.

(5) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. The electric utility may consider 100% of applicable loading, if available, instead of 15% of line section peak load.

(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's maximum load or 50 kWac.

Commented [DTEE13]: Or implement a non-sell back protection scheme to not exceed the customer load.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling.

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers.

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen
3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the DER's nameplate rating must be less than 250 kWac. This screen does not include substation voltage regulators.

(6) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection agreement must proceed under R 460.962.

(7) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (4) of this rule.

(d) Withdraw the interconnection application.

(8) If the applicant does not select a course of action under subrule (7) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant's request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(7).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(4).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (6) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may include additional supplemental review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, the electric utility shall provide a detailed technical rationale for the inclusion of each supplemental review screen. If an additional screen negates or undermines any of the supplemental review screens specified in subrule (6) of this rule, the rationale must include an explanation of the technical justification for the additional screen.

(3) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(4) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(5) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, an electric utility shall perform a supplemental review and notify the applicant of the results. The supplemental review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (2) of this rule to the proposed DER. The electric utility shall not require a system impact study if the DER passes the applied supplemental review screens.

(6) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (7) and (8) of this rule. All of the following must be applied by the electric utility:

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in this subdivision. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section may not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal ~~and~~ ~~emergency~~ ampacity.

Commented [DTEE14]: Emergency ampacity is reserved for limited duration system security.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(7) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be

interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(8) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(9) For subrules (7) and (8) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the simplified track, the non-export track, or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the simplified track or the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted pursuant to R 460.936, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), (d), or (e) of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide an individual study agreement or a batch study agreement to the applicant, whichever is applicable under subrule (4) of this rule.

(4) An electric utility shall study all interconnection applications that qualify for study track either individually or in a batch study process. An electric utility shall not study 1 or

more applications individually and at the same time study 1 or more different applications as part of a batch.

(5) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities impact study fee.

R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs. An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility has elected to study all interconnection applications that qualify for study track individually.

(b) An electric utility determined the application to be complete and conforming.

(c) An application qualifies for study track pursuant to R 460.952.

(d) An interconnection application has a pre-application report, when required by R 460.936(2).

(e) An applicant has paid all required fees.

(f) An applicant has signed and returned an individual study agreement.

(5) If an electric utility anticipated that it would use a batch study process but received only 1 interconnection application that qualified for the study track, the electric utility shall consider the first day of what would have been the batch study process to be the day the application was determined to be complete and conforming and shall use the individual study process to evaluate the application with all applicable timelines.

R 460.956 Batch study process.

Rule 56. (1) This rule applies only to those electric utilities that have elected to study DERs that qualify for study track in a batch process.

(2) A batch consists of 2 or more interconnection applications that will be studied as a group by the electric utility. One or more DERs in the batch that are electrically remote may be studied on an expedited schedule, but expedited scheduling of 1 or more DERs may not cause unreasonable delays in the evaluation of the other DERs in the same batch.
(3) An electric utility shall process at least 1 batch per year. The start and end dates for each batch study must be published on the electric utility's public website not less than 60 days prior to the start of the batch.
(4) Interconnection applications that meet all of the following requirements must be admitted into a batch study:
(a) The electric utility elected to study all interconnection applications that qualify for study track in a batch study process.
(b) The electric utility considered the application complete and conforming within a 1-year period immediately before the batch study commences.
(c) The accepted application qualifies for study track pursuant to R 460.952.
(d) The interconnection application has a pre-application report when required by R 460.930(2).
(e) The applicant has paid all required fees including any milestone payments as described in the electric utility's interconnection procedures.
(f) The applicant has signed a batch study agreement.
(5) An electric utility shall offer to hold a scoping meeting, either in-person or via telecommunications, with every applicant in a batch. The scoping meetings and the electric utility must meet all of the following requirements:
(a) All meetings must, to the extent feasible, take place within 30 days of the batch start date.
(b) An electric utility shall not begin studies within a batch until it has held a scoping meeting with every applicant who agreed to participate in a meeting. An electric utility may begin the batch study if an applicant is unreasonably delaying a meeting.
(c) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting. An electric utility may meet with multiple applicants in the same meeting if agreed to by the electric utility and all the applicants that will attend the meeting.
(d) During the scoping meeting, the electric utility shall identify and communicate to each applicant the studies it plans to perform and estimate the cost of the batch study, using either the fees that comply with R 460.926, or, if interconnection procedures have been approved by the commission, fees that comply with the interconnection procedures. The cost estimate must assume that all applicants will stay in the batch throughout the batch study.
(6) The batch process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. The electric utility may specify additional studies it may perform on a batch study in its interconnection procedures.
(7) Interconnection applications within a batch must be considered to have equal priority with each other.
(8) An electric utility shall follow R 460.960(1) and (2) when conducting a system impact study.
(9) An electric utility shall follow R 460.962(1) when conducting a facilities study.

(10) An electric utility shall provide written study results to each applicant at the completion of each study during the batch study. An electric utility shall offer to hold a conference call with each batch applicant at the completion of each study phase, with the electric utility making reasonable efforts to accommodate applicants' availability when scheduling the call. An electric utility may choose to group the consultation of multiple projects by the applicant and its affiliates into the same conference call. The conference call must provide a summary of outcomes and answer questions from applicant. All conferences regarding the study results should be held within 30 business days following completion of each study phase.

(11) Within 45 business days following the completion of each study phase, the applicant shall choose to either continue to the next study phase of the batch study or withdraw. The fee for the next study phase in the batch study is due by the end of the 45 business days, unless extended by the electric utility. An applicant that withdraws from the study may reapply with a new interconnection application.

(12) Applicants may reduce the capacity of the DER by up to 20% during the decision period between study phases until the conclusion of the system impact study. If the applicant wants to increase the capacity of the DER, the electric utility may require the applicant to submit a new interconnection application and pay the appropriate fees.

(13) Within 45 business days of the applicant receiving the final batch study report from the electric utility, the applicant shall notify the electric utility of its plan to proceed to R 460.964 for an interconnection agreement or withdraw its interconnection application. If the applicant fails to notify the electric utility within 45 business days, the electric utility may withdraw the interconnection application.

(14) If an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, the other interconnection applications in the batch must continue to progress through the batch study process. If feasible, considering the status of the batch study, the delayed interconnection application may rejoin the batch study after the affected system issue is resolved. An interconnection application that is the subject of informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, may rejoin the batch study at a later date, if feasible, considering the status of the batch study.

(15) A batch study is considered complete 45 business days after all batch applicants, except those applicants whose DERs are either causing unresolved affected system issues, pursuing informal mediation pursuant to R 460.904, pursuing formal mediation under R 460.906, or pursuing a complaint under R 792.10439 to R 792.10446, have withdrawn, voluntarily or otherwise, or have received the final study results from the electric utility.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to those electric utilities that have elected to individually study DERs that qualify for study track.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.

(4) The scoping meeting may occur in-person or via telecommunications.

(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study, or an interconnection agreement and the basis for that decision, and 1 of the following must occur:

(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.

(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.

(c) The interconnection application must proceed to R 460.964 for an interconnection agreement.

R 460.960 System impact study agreement, scope, procedure, and review meeting.

Rule 60. (1) For all DERs being studied individually or as part of a batch, all of the following apply:

(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.

(b) A system impact study agreement must include all of the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.

(iv) A timeline for completion of the system impact study.

(v) A list of the information that must be provided to the applicant in the system impact study report.

(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.

(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.

(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.

(2) For DERs being studied as part of a batch, an electric utility may request reasonable additional data from the applicant during the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the batch study within the 1-year timeframe specified in R 460.956. An electric utility may not be found in violation of these rules when 1 or more applicants impede the batch study process through applicant delays, demands, complaints, litigation, objections, or other similar actions.

(3) For DERs being studied individually, all of the following shall apply:

(a) The electric utility shall complete the system impact study and the system impact study report. If necessary, the electric utility shall transmit a facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data**.**

(b) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subdivision (a) of this subrule.

(c) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(d) Upon request by the applicant pursuant to subdivision (c) of this subrule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(e) At the system impact study review meeting, the electric utility shall offer the applicant all of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(iii) Withdraw the interconnection application.

(f) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.

(g) The system impact study review meeting may occur in-person or via telecommunications.

R 460.962 Facilities study agreement, scope, procedure; review meeting.

Rule 62. (1) For DERs being studied individually or as part of a batch, all of the following apply:

(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. If no system impact study was performed, the electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.

(b) The facilities study agreement must include the following:

(i) An outline of the scope of the study.

(ii) The applicable fee.

(iii) A timeline for completion of the facilities study.

(iv) A list of the information that will be provided to the applicant in the facilities study report.

(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.

(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. The electric utility shall provide cost estimates that are detailed and itemized.

(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.

(2) For DERs being studied individually, all of the following are required:

(a) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee.

(b) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:

(i) Request a facilities study review meeting with the electric utility.

(ii) Proceed to an interconnection agreement pursuant to R 460.964.

(iii) Withdraw the interconnection application.

If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.

(c) Upon request by the applicant pursuant to subdivision (b)(i) of this subrule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.

(d) At the facilities study review meeting, the electric utility shall offer both of the following options:

(i) Proceed to an interconnection agreement pursuant to R 460.964.

(ii) Withdraw the interconnection application.

(e) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.

(f) The facilities study review meeting may be conducted in-person or via telecommunications.

R 460.964 Interconnection agreement.

Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement to an applicant within 3 business days of reaching this stage.

(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement with modifications to address required construction activities, construction milestone timing, and cost to an applicant within 5 business days of reaching this stage. The applicant and electric utility shall mutually agree on the timing of construction milestones.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the standard level 1, 2, and 3 interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the standard level 1, 2, and 3 interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility did not receive the signed standard level 1, 2, and 3 interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subdivision (b) of this subrule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, the formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the standard level 1, 2, and 3 interconnection agreement within 10 business days of the applicant returning the signed standard level 1, 2, and 3 interconnection agreement.

(5) For level 4 or 5 projects, the electric utility shall provide its level 4 and 5 interconnection agreement within 10 business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the level 4 and 5 interconnection agreement must contain either timelines for completion of activities and estimates of construction costs or a timetable when these requirements can be determined. The interconnection agreement must include a payment schedule that corresponds to the milestones established and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the level 4 and 5 interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility does not receive the signed level 4 and 5 interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subdivision (b) of this subrule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility's standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting batch studies, if either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment prior to the electric utility beginning the study phase of the next batch study pursuant to R 460.956, the electric utility may not include the interconnection application in the system baseline for conducting the next batch study. If the interconnection application is electrically coincident with other interconnection applications in the next batch study, the electric utility may require the withdrawal of the interconnection application.

(ii) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant prior to being incurred. The cost may not exceed 125% of the estimate without the consent of the applicant prior to the costs being incurred.

(9) A party's obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:

(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.

(b) Propose the earliest alternate date when it can attain this and future milestones.

(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.

(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:

(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.

(b) The milestone under question has been previously delayed.

(c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.

(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.

(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades. Both of the following apply regarding the final accounting:

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute. Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER.

(b) If the applicant's previous aggregate payments exceed its costs under the construction agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations, provided that these modifications do not alter the rights or obligations of the interconnection customer.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. The electric utility's interconnection procedures must describe the technical requirements of these items.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the standard level 1, 2, and 3 interconnection agreement or level 4 and 5 interconnection agreement.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days.

(4) If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within either of the following:

(a) Ten business days of receiving the notification from the applicant pursuant to subrule (2) of this rule, for level 1, 2, and 3 applications.

(b) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to subrule (2) of this rule for level 4 and 5 applications.

(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests. If the electric utility waives this right, both of the following apply:

(a) It shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.

(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.

(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.

(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.

(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.

Commented [DTEE15]: This section is not referenced by number or description except in the legacy net metering rules and the flow charts. The Interconnection agreement construction terms being completed should lead to this section.

Commented [DTEE16]: Common items can be in the procedures, Site specific requirements may be called out in the interconnection construction agreement.

Commented [DTEE17]: What happens if the applicant's documents are incomplete, insufficient or do not meet the requirements, should this have similar language to 7b? It will be more efficient for both the customer and utility to catch deficiencies and resolve them before committing to field inspections or final testing.

Commented [DTEE18]: 5b allows a customer 20 business days to provide information for a desk review, but 4a only allows 10 business days to coordinate with the customer and physically visit a site?

Also, this only addresses the simplest cases, Level 1,2,3 projects may (especially in commercial tariffs) have required service/metering upgrades or shutdowns, replacement of equipment, installation or reconfiguring of relaying etc, or consist of multiple phases of development and may require mutual agreement as to the specific timing to accommodate customer schedules and utility operations. This provision should be 20 business days and mutual agreement should be an option as well.

(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report as follows:

(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.

(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.

R 460.968 Authorization required prior to parallel operation.

Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:

(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.

(b) The applicant complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.

(c) The applicant complied with all applicable local, state, and federal requirements.

(d) The electric utility received full payments for all outstanding bills.

(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.

(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.

(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.

R 460.970 Cost allocation of interconnection facilities and distribution upgrades.

Rule 70. Costs for interconnection facilities and distribution upgrades must be classified into 1 of the following categories:

(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs. These costs must be assigned to the cost-causing applicant.

(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

R 460.974 Interconnection metering and communications.

Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.

(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.

Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.

(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.

Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:

(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).

(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).

(c) Termination of interconnection by mutual agreement.
(d) Distribution system emergency, but only for the time necessary to resolve the emergency.
(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.
(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.
(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.
(h) Other material noncompliance with the interconnection agreement.
(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.
(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

R 460.980 Capacity of the DER.
Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the new nameplate capacity of the DER. The maximum capacity of a DER is the aggregate nameplate capacity or may be limited as described in the electric utility's interconnection procedures.
(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures.
(3) The electric utility's interconnection procedures must describe acceptable methods for power limited export DER including, but not limited to, reverse power protection and utilizing inverters or control systems so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported.

R 460.982 Modification of the interconnection application.
Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform a cursory evaluation to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business day.
(2) The electric utility shall not be required to accept or implement a modification to the electric utility's distribution system or generation assets that is proposed by an applicant or affected system operator.

(3) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.

(4) For a proposed modification which the electric utility has determined is a material modification, the applicant may request a material modification review to determine whether the material modification is an acceptable material modification or an unacceptable material modification. The electric utility shall complete the material modification review and determine which of the following options are available to the applicant:

(a) If the modification is an unacceptable material modification, the applicant may withdraw the modification or withdraw the application.

(b) If the modification is an acceptable material modification and requires minimal or no restudy, the application study activities will resume with the modification and no change to the timing.

(c) If the modification is an acceptable material modification but requires restudy, the electric utility shall expedite the restudy. The applicant shall pay any required fee for the expedited restudy.

(5) The applicant may request a 1-hour consultation to discuss the results of the material modification review.

(6) The applicant shall notify the electric utility of its selection pursuant to subrule (4) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.

(7) If the proposed modification is determined not to be a material modification or is determined to be an acceptable material modification, the electric utility shall notify the applicant that the proposed modification has been accepted.

(8) If the modification is considered an unacceptable material modification, the applicant shall withdraw the proposed modification, or initiate mediation pursuant to R 460.904 or R 460.906, or file a complaint pursuant to R 792.10439 to R 792.10446 within 10 business days of receipt of the decision, or proceed with a new interconnection application for this modification. If the applicant does not provide its determination within the 10 business days, the electric utility may consider the interconnection application withdrawn.

(9) Any modification to the interconnection application or to the DER that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.

(10) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.

(11) Replacing a component with another component that has near-identical characteristics does not constitute a material modification.

(12) The electric utility's interconnection procedures must provide examples of modification that are not material modifications, acceptable material modifications, and unacceptable material modifications.
(13) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.
Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant may not begin any material modification to the DER until the electric utility has accepted the new interconnection application and completed at least one of the following:
(a) An initial review.
(b) A supplemental review.
(c) A system impact study.
(d) A facilities study.

Commented [DTEE19]: The applicant should only proceed with executing material modifications to the DER if they have an executed Interconnection agreement. For example if an initial review indicated supplemental review is needed to accept the modification, then it is not decided that the modification will not require further changes before being implemented.

R 460.986 Insurance.
Rule 86. (1) An applicant interconnecting a level 1 or 2 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.
(2) An electric utility shall not require an applicant interconnecting a level 1 or 2 project to name the electric utility as an additional insured party.
(3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.
(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.
(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $3,000,000.

R 460.988 Easements and rights-of-way.
Rule 88. If an electric utility line extension is required to accommodate an interconnection, the applicant is responsible for procurement and the cost of providing and obtaining easements or rights-of-way.

R 460.990 Interconnection penalties.
Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems

within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Catastrophic conditions.
Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to catastrophic conditions as defined in R 460.702(f). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.
Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.
Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.
(2) Within 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.
(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.
(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.
(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.
(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.
(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less

than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.

(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. Energy storage devices must be configured to prevent export of stored electricity to the distribution system. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period.

(8) An applicant shall notify the electric utility of plans for any material modification to the project. An applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application, including any necessary system impact study or facilities study. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

Commented [DTEE20]: This should also refer to 460.1026 ("A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.")

R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on the legacy net metering program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subdivision (a) of this subrule, if practicable, or adopt the review process pursuant to subdivision (c) of this subrule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may

consider the legacy net metering application withdrawn without refund of the application fees.
(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.
(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.
(e) The electric utility shall complete changes to the customer's account to permit the distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.
(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.
(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.
(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.
(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.
(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.
(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.
(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.
(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

Commented [DTEE21]: This should say legacy net metering program since this is the legacy net metering section.

R 460.1006 Distributed generation program application and fees.
Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.
(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968. The following shall also apply.
(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the distributed generation program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.
(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.
(ii) While processing the interconnection application, which may include, but is not limited to, R 460.940 simplified track or R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.
(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subdivision (a) of this subrule, if practicable, or adopt the review process pursuant to subdivision (c) of this subrule.
(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:
(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility

notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility’s notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.

(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(5) If a customer’s distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer’s application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.

(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility’s distributed generation program tariff sheet or in the alternative electric supplier’s distributed generation program plan.

(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer's interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.

Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.

(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.

(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.

(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.

Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.

Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer’s power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer’s meter is not capable of measuring and recording the customer’s power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer’s power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of

measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility.

Commented [DTEE22]: This should clarify that pursuant to 460.1026 legacy net metering customers can only remain on legacy net metering for a certain time-period, not indefinitely.

R 460.1022 Renewable energy credits.

Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.

(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.

(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.
Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.
Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	))))))	Case No. U-20890

PROOF OF SERVICE

ESTELLA R. BRANSON states that on November 1, 2021, she served a copy of the DTE Electric Company's Comments in the above captioned matter, via electronic mail, upon the person listed on the attached service list.

____

ESTELLA R. BRANSON

MPSC Case No. U-20890
SERVICE LIST

MPSC STAFF
Steven D. Hughey
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Public Service Division
7109 W. Saginaw Highway, Fl 3
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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.	))))))	Case U-20890

COMMENTS OF THE MICHIGAN ELECTRIC AND GAS ASSOCIATION

Pursuant to the Commission's September 9, 2021 Order establishing a public hearing for administrative rules governing Michigan's electric interconnection and distributed generation programs, the Michigan Electric and Gas Association[1] submits these comments in response to the Commission's request for public comment regarding the draft rules.

I. Introductory Comments

MEGA appreciates the opportunity to provide these public comments concerning the Interconnection and Distributed Generation Standards Ruleset 2019-3 with the Michigan Public Service Commission.

As the Commission is aware MEGA members have much smaller staffs, programming, and smaller information technology budgets to provide interconnection services that are required under these draft rules. MEGA requests, where appropriate, adequate flexibility be provided to utilities when needed for effective review and management of the complex interconnection process.

[1] The MEGA member companies are investor-owned natural gas and electric utilities with fewer than 500,000 customers in the state of Michigan, and include: Alpena Power, Citizens Gas Fuel Company, Indiana Michigan Power, Michigan Gas Utilities, Northern States Power Company – Wisconsin, SEMCO Energy Gas Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company.

For example, having additional time for some of the requirements in the application and site inspection process would be extremely beneficial to MEGA members. We suggest moving from 10 business days for applications and inspections to 30 business days, knowing that many applications and inspections will be straightforward and without issue. But having adequate time to properly schedule the review and inspection would be helpful. As an alternative, the Association would request some form of flexibility being written into the rules that allows a utility in limited circumstances to extend beyond a deadline to accommodate MEGA members' smaller staffs and resources.

Many of these rules will require additional investments that are not currently contemplated by many MEGA members, whether that's potential information technology upgrades or additional staff due to the requirements of the process laid out in these rules. As an example, some of our utilities will have to create new systems to manage this complex process.

Further, while not the focus of these rules, MEGA remains concerned that this ruleset could result in additional cost shifts that may be unintended consequences, exacerbating existing subsidy issues between distributed generation/legacy net metering customers, and non-distributed generation/legacy net metering customers.

Finally, MEGA remains concerned that this ruleset is premature, as there will likely need to be revisions based on FERC Order 2222 implementation in 2022.

Again, the Association appreciates the opportunity to provide feedback on these rules. Specific comments for each Section of the Rules and the Rule number are listed below.

II. Specific Rule Comments

Part 1. General Provisions

Rule 460.1a(cc) Definitions; A-I

Some MEGA members currently provide consolidated Distribution Impact Study reports which include results from Feasibility, Impact, and Facilities studies.

Separating these studies will align with Regional Transmission Operator (RTO) methodology but will significantly increase time and costs to study applications and delay the ability of customers to make decisions for distribution interconnections.

Rule 460.1b(e) – (i) Definitions; A-I

These prescribed levels are not effective in correlating requirements for review and cost causation. Even small facilities less than 20 kW may require detailed study and analysis, and systems greater than 1MW may have no impacts to the bulk system at all.

These Levels are also fundamentally divergent from all other jurisdictions in that they do not have an escalation method, i.e., if something fails at level 2 it advances to Level 3.

Additionally, some MEGA members operate effectively with a 3-level review/study process that can treat all applications equally while still being able to provide rapid approval for over 90% of all applications.

Rule 460.1b(j) Definitions; J-Z

Like the comments on R460.1b(e)-(i), Interconnection Agreements should be more agnostic to size and deal more with guidelines for safe operation. A small residential system may require special and specific operational requirements that a 1MW+ facility may not simply due to the local impacts. Importantly, those impacts can’t be pre-determined simply by size of facility with no evaluation of the Area Electric Power System.

Rule 460.1b(s) Definitions; J-Z

MEGA suggests that the Nameplate Rating should also include Ah and kWh ratings for Energy Storage.

Rule 460.1b(nn) Definitions; J-Z

MEGA suggests an alternative, standard term for a combined Feasibility, Impact, and Facilities study would be helpful for Distribution Interconnections to avoid duplication of RTO and other state's names of studies.

Rule 460.904 Informal mediation

MEGA remains concerned on the aspects of cost for implementing a system for each utility that can track necessary information for mediation proceedings. Some of our members estimate costs upwards of $3 - $4 million to implement and manage their systems in Michigan.

Further, additional staff will be necessary to effectively manage the system, answer questions.

Finally, MEGA remains concerned that these rules are premature given the current regulatory conditions. For example, these rules may need to be revisited to accommodate wholesale processes due to implementation of FERC Order 2222.

Rule 460.908

MEGA notes this will have increased costs for its members to implement and manage.

Part 2. Interconnection Standards

Rule 460.914 Transition non-study group

MEGA members are concerned that these rules will result in additional cost and staff, assigned to their Michigan operations, to effectively manage. Further, it is unclear how these rules would impact existing requests once effective.

Rule 460.916 Legacy applications

MEGA members do not always have Construction Agreements typically that delve into the DER commissioning aspect of the construction, just the building of facilities. Post Commissioning requirements are typically not spelled out in this agreement.

Rule 460.918 Transition batch study process

This rule does not contemplate nor effectively manage when all the applicants enter on the same day. For example, in PJM's similar queue, many applicants enter on the last day, preventing the utility from doing any pre-model work on the project. To that end, with the timeline requirements listed below, there is concern that feasibility study results can be delivered in 1 year for everyone since the whole group must be ready before moving to the next step.

Further it is not clear if this process will be separate from a FERC Order 2222 process.

Rule 460.918(8)(b) Transition batch study process

With no definition for 'unreasonably delaying,' it is unclear who makes the determination as to what constitutes the delay, or who arbitrates the issue.

Rule 460.918(10) Transition batch study process

MEGA asks whether this means that the studies must be delivered in the order that they are applied? Or that the EDU cannot get out of "order" of when the batch is received? Or does this mean that all studies must be delivered at one time 6 months after the date of the batch closure? This would include un-answered sections of the study templates if the developer hasn't answered utility questions in full.

MEGA is also concerned that this will create issues when developers compete over access to constrained systems. If two developers propose 1MW+ systems on the same circuit they will almost certainly be electrically coincident, and if one developer applies at the start of the queue and someone puts their application in at the end it could be 6 months apart, and utilities would be required to treat these applications as if they came in simultaneously and as if they were both going to be online.

Rule 460.918(15) Transition batch study process

There is concern here that this is not feasible because the reduction will have to be re-studied and re-modeled in the planner's contingency process.

Rule 460.922 Online applications and electronic submission

Many MEGA members will require updates to their systems to accommodate the electronic application and submissions, including for meeting the extensive daily, monthly, and batching requirements.

Rule 460.924 Communications

MEGA members are concerned there is a lack of clarity in this section. Specifically, from a resource management standpoint, additional staff or staff time will need to provide "reasonable assistance" to applicants or interconnection customers.

It is not clear how the application agents will be registered and identified to the utility. While the Rule contemplates the designation, it does not ascribe a process or the information necessary to effectuate that.

Finally, the indemnity suggested under (3) for assistance provided by the interconnection coordinator(s) will require some form of security deposit because each application will require some form of monitoring.

Rules 460.926 and 460.928 Initial fees and **Fee and fee cap modifications**

MEGA appreciates the recognition there are costs involved for the determination of interconnection, however, some of the cost items, particularly on the pre-application fee, are likely insufficient to cover costs to review applications. Further, it is not clear who is collecting the fees. Fees should not be a "one-size-fits-all" approach when the size of applications will vary greatly.

Rule 460.934 Site control

MEGA is seeking clarity that if the party interconnecting the DER is not the business or homeowner, would the interconnecting party need to register so they can operate on behalf of the business or homeowner?

Rule 460.936 Interconnection applications

MEGA recommends that proof of Insurance should be required for customers with existing service at all levels. Further, all electrical diagrams should be stamped by a professional engineer regardless of size or level.

MEGA also suggests that when applications are rejected for failure to be complete and conforming, this reason for rejection should be identifiable and communicated to the customer by the interconnecting party.

Rule 460.938 Public interconnection list

MEGA appreciates the Commission's effort to balance the interests of transparency, but there should be an avenue to protect sensitive information in the process.

Rule 460.944 Fast track applicability

MEGA recommends that utilities should have the option to elevate level 1 & 2 applications to Fast Track if simplified fails, or alternatively to move something in the Study Track down. Adding this caveat would allow utilities to implement the process more effectively with existing processes.

Rule 460.946 Fast track; initial review

Members remains concerned that this section may not properly align with the batch study concept.

Further, there is concern that it will be difficult for smaller utilities to maintain a batching process and verify fault current points every 20 days.

Rule 460.964 Interconnection agreement

MEGA argues that modifying Interconnection Agreements to accommodate customer specific circumstances can occur with or without physical construction, and that dedicated staff will be needed to draft, review, and approve such modifications. Therefore, the rule should be adjusted to stipulate that the electric utility will provide a DRAFT of Interconnection Agreement language within 20 business days.

MEGA also remains concerned that the timelines here are very aggressive for smaller utilities, who have limited resources, to implement. Having either modified timelines for smaller utilities or an avenue to request additional time from the Commission would be helpful in the limited cases where an agreement takes longer to implement for various policy, legal, and resource reasons.

Rule 460.976 Post commissioning remedy

MEGA expresses concern that this Rule may not confer appropriate authority to enter the premises of the interconnection customer to determine compliance.

Rule 460.984 Modifications to the DER

MEGA remains concerned that there are no penalties for the applicants should they choose to modify and inform/request modification after the fact.

R 460.986 Insurance.

MEGA is concerned the rules do not define what types of liability insurance are required. As the rules are currently written, exclusions could be added to the policy that defeat the purpose of the liability insurance. For example, MEGA members have seen exclusions for stray voltage claims, claims related to subsidence, any occurrence that happens on or after the first day of commercial operation, electromagnetic frequency in other states.

MEGA recommends that liability insurance include insuring against all claims for property damage and for personal injury or death arising out of, resulting from, or in any manner connected with the installation, operation, and maintenance of the DG facility.

Additionally, it should be made clear the utility has the option to review insurance policies at any time and take action against deficient policies (reject interconnection or disconnect).

MEGA recommends adding language to the section that the public utility can review the entire liability insurance of the DG facility at any time and has the ability to reject interconnection or disconnect interconnection if the insurance is inadequate.

III. Conclusion

As shown by these comments, the MEGA utilities are concerned that the proposed rules governing electric interconnection and distributed generation programs will require additional staffing to meet strict timelines, will require significant investment in IT and programing costs to implement rules that applicable to their small customer base. The MEGA utilities have and will continue to address interconnection and DG programs applications on a successful basis without the need for burdensome regulatory oversight/rules.

Sincerely,

Dated: November 1, 2021

Daniel Dundas
President
Michigan Electric and Gas Association

DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

Jon P. Christinidis
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June 27, 2022

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.
MPSC Case No. U-20890

Dear Ms. Felice:

Attached for electronic filing in the above-captioned matter is DTE Electric Company's Comments pursuant to the Michigan Public Service Commission's May 12, 2022 and May 26, 2022 Orders in Case No. U-20890.

Very truly yours,

Jon P. Christinidis

JPC/erb
Attachments
cc: Service List

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	)	Case No. U-20890

<u>COMMENTS OF DTE ELECTRIC COMPANY</u>

<u>Introduction</u>

On May 12, 2022, the Michigan Public Service Commission ("Commission" or "MPSC") issued an Order in this proceeding in response to a Joint Petition of DTE Electric Company and Consumers Energy Company. In the Order the Commission granted the Joint Petition and indicated that the Commission would provide a second opportunity for public comment. (Case No. U-20890 Order dated May 12, 2022, p. 10) On May 26, 2022 the Commission issued an additional Order issuing (as Exhibit B) forty-nine (49) pages of proposed interconnection rules, establishing a public hearing date of June 22, 2022 and allowing any person to file *"comments, suggestions, data, views, questions, argument, and modifications concerning the issues"* by 5:00 pm June 27, 2022. (Case No. U-20890 Order dated May 26, 2022, p. 4)

The Company appreciates the additional opportunity to provide comments regarding the proposed Interconnection and Distributed Generation Standards which the Commission describes as the "MIXDG rules" (hereinafter the "newly proposed rules") and proposed recission of the Electric Interconnection and Net Metering Standards (hereinafter the "existing rules"). In light of the limited time frame to provide comments and the voluminous and complex nature of the newly proposed rules, the Company's written comments focus on conceptual concerns and include an attached redline markup (with margin comments) of the newly proposed rules (attached as Exhibit A) designed to, in part and among other things, address those matters and various other technical concerns. The Company's prior comments and suggestions regarding interconnection rulemaking in this and other dockets are incorporated by reference as if fully restated herein. Failure to address each and every provision of the newly proposed rules should not necessarily be construed as agreement by the Company.[1]

DTE Electric is fully committed to providing a positive customer experience for all customers. The Company serves over 2 million customers in Southeast Michigan across a service territory that covers over 7,600 square miles, with a distribution system that includes over 31,000 miles of overhead lines, and over 16,000 miles of underground lines. The Company recognizes that our customers share our enthusiasm for clean energy and know that many want to be more involved in their energy supply, thus we strive to accommodate interconnection requests as quickly and safely as possible.

However, it bears emphasis that virtually the entire electric utility industry in the state has expressed serious concerns regarding the newly proposed rules, including with respect to safety, reliability, and proper payment for the costs associated with interconnection to electric utility distribution systems. While some portions of the newly proposed rules are helpful in, for example, requiring interconnection applicants to maintain reasonable progress in pursuing their project, the newly proposed rules also impose unnecessarily complex and prescriptive processes affecting safety, reliability, proper cost recovery, and a variety of other issues likely to result in confusion, errors, misunderstandings and disagreement.

[1] DTE Electric reserves all rights to further address interconnection issues in this and/or other dockets as well as in appeals.

The Company believes that this complexity is unnecessary and the rationale for promulgating new rules is not well explained or supported by meaningful facts or data. The vast majority of interconnections to the DTE Electric distribution system are accomplished without significant issue. In fact, the Company has successfully interconnected over 6,000 small generators to its distribution system since the enactment of 2008 PA 295.

Applying the Proper Scope of Rulemaking is Critical

The Administrative Procedures Act provides that:

> *"A rule must not exceed the rulemaking delegation contained in the statute authorizing the rulemaking."* (MCL 24.232(7))

Because the Company and others have previously explained the various legal (and technical) concerns in this docket, rather than completely reiterate them, the Company highlights some of the more critical concerns and incorporates the remainder by reference as if fully restated herein. (See, by way of example and not limitation, the following pleadings filed in this docket: *DTE Electric Company's Comments dated November 1, 2021, DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing dated April 14, 2022, Answer of Indiana Michigan Power Company to Joint Petition for Rehearing dated May 4, 2022, Answer of the Michigan Electric and Gas Association to Joint Petition for Rehearing dated May 4, 2022, Answer of the Michigan Electric Cooperative Association to Joint Petition for Rehearing dated May 4, 2022*) The only specific grants of authority identified by the Commission with respect to the newly proposed rules include MCL 460.10e (addressing generally "merchant plants")[2] and MCL 460.1173 (addressing

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[2] Most relevant to the instant rulemaking, MCL 460.10e provides: *"**The commission shall establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations.** The standards shall be consistent with generally accepted industry practices and guidelines and shall be established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public. **The merchant plant will be responsible for***

generally "distributed generation programs")[3]. MCL 460.10e was enacted more than 20 years ago. Much of what is now MCL 460.1173 has been in place since 2008, although modified in some respects in 2016.

In Consumers Power Co v Public Service Comm, 460 Mich 148, 155-56; 596 NW2d 126 (1999), our Supreme Court explained:

> "The Public Service Commission has no common-law powers. It possesses only that authority granted by the Legislature. Union Carbide v Public Service Comm, 431 Mich 135, at 146, 428 N.W.2d 322. Moreover, this Court strictly construes the statutes which confer power on the PSC. As this Court explained in Union Carbide, supra at 151, 428 N.W.2d 322, quoting Mason Co. Civic Research Council v Mason Co, 343 Mich 313, 326–327, 72 NW2d 292 (1955):
>
> "The power and authority to be exercised by boards or commissions must be conferred by clear and unmistakable language, since a doubtful power does not exist."

Noncompliance with the APA is reversible error. In re Public Service Commission Guidelines for Transactions Between Affiliates, 252 Mich App 254, 267; 652 NW2d 1 (2002) provided:

> *"Invoking the public interest and the need for policy that is responsive to a changing industry, the PSC eschewed the procedural mandates of the APA in favor of its own course of action . . . While we do not doubt the PSC's legitimate concerns . . . the process utilized by the PSC constituted a rather heavy-handed rebuke of*

all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery." (MCL 460.10e(3); emphasis added)

[3] *As it relates specifically to rulemaking, MCL 460.1173 provides: "**The commission shall establish a distributed generation program by order** issued not later than 90 days after the effective date of the 2016 act that amended this section. **The commission may promulgate rules the commission considers necessary to implement this program. Any rules adopted regarding time limits for approval of parallel operation shall recognize reliability and safety complications including those arising from equipment saturation, use of multiple technologies, and proximity to synchronous motor loads…If necessary to promote reliability or safety, the commission may promulgate rules that require the use of inverters that perform specific automated grid-balancing functions to integrate distributed generation onto the electric grid.***" (MCL 460.1173(1)(5)(b); emphasis added)

established APA procedures, and, accordingly, we are compelled to invalidate that process" (252 Mich App at 267-68).[4]

The Commission cannot re-write the Legislature's language to include new or different provisions. Hanson v Mecosta Co Rd Comm, 465 Mich 492, 501-503; 638 NW2d 396 (2002). If a Commission order conflicts with a statute, the order is void. Manufacturers Nat'l Bank v DNR, 420 Mich 128, 146; 362 NW2d 572 (1984). Our Supreme Court recently reaffirmed that *"agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature."* In re Complaint of Rovas Against SBC Michigan, 482 Mich 90, 98; 754 NW2d 259 (2008) (Emphasis added).

In light of the thousands of successful interconnections to DTE Electric's and other Michigan electric utilities' distribution systems, relatively static law, and limited *"clear and unmistakable"* direction to promulgate rules it is likely that the newly proposed rules have exceeded the Commission's legislative directives.

Another example includes application of the newly proposed rules to *limit electric utilities' management authority and use of their own property* for their own business purposes – including electric utility-owned generation and distribution systems. Newly proposed rules R 460.901(a)(h) and (vv) as well as R 460.936(8) and (9) are implicated and all restrictions set forth in those

[4] Allowing third parties to control electric utility property (its distribution system) and undercharging generators for access to and use of that property presents an additional, constitutional problem because the Company's private property is essentially being taken by another private entity. Mich Const 1963, art 10, §2 provides that: *"Private property shall not be taken for public use without just compensation therefor being first made or secured in a manner prescribed by law."* The Fifth Amendment of the United States Constitution similarly provides that *"the government may not take private property unless it is done for a public use and with just compensation."*[4] Taking electric utilities' private property and giving it to other private entities (merchant plants) violates the "public use" requirement. The Commission's authority does not include the ability to take property for the private use of another.

provisions (or any other) purporting to restrict an electric utility's utilization of its own property must be removed.[5]

The bounds of regulation are aptly described in Union Carbide v. Public Service Comm., 431 Mich 135; 428 NW2d 322 (1988)

> *"The power to fix and regulate rates, however, does not carry with it, either explicitly or by necessary implication, the power to make management decisions. 'It must never be forgotten that while the State may regulate with a view to enforcing reasonable rates, it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership.' [citations omitted]".*

It is clear that the Commission is principally an economic regulator and not the operator of electric utility facilities. There is no relevant administrative rulemaking authority to the contrary. Ford Motor Co. v. Public Service Comm, 221 Mich App 370, 385, 387-388; 562 NW2d 224 (1997) (*"The PSC here exceeded its ratemaking authority by, in effect, requiring Detroit Edison's management to adopt the DSM program the PSC thought best."*); Attorney General v. Public

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[5] The referenced provisions relevantly provide:

> *(h) "Applicant" means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility.* ***An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.*** (R 460.901(a)(h); emphasis added)
>
> *"(vv) 'Interconnection customer' means the person or entity,* ***which may include the electric utility****, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures."* (R 460.901(a)(vv); emphasis added)
>
> *" (8)* ***An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system****, with the exception of temporary DERs."* (R 460.901(8); emphasis added)
>
> *"(9)* ***An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility****, its subsidiaries or affiliates, or others, with the exception of temporary DERs."* (R 460.936(9); emphasis added)

Service Comm, 269 Mich App 473; 713 NW2d 290 (2005) (MPSC exceeded its authority when it ordered the utility to expand its "green power" program and required customers who did not participate in the program to subsidize its costs). Consumers Power Co, Public Service Comm, 189 Mich App 151, 180; 472 NW2d 77 (1991) *("To the extent that the PSC actually ordered Consumers to enter, or not enter, into any particular contract, it exceeded its authority")*.[6]

The Commission is an *"administrative body created by statute and the warrant for the exercise of all its power and authority must be found in statutory enactments."* Union Carbide v Public Service Comm, 431 Mich 135, 146; 428 NW2d 322 (1988); Sparta Foundry Co v Public Utilities Comm, 275 Mich 562, 564; 267 NW 736 (1936). The Commission's authority must be conferred by clear and unmistakable statutory language, and a doubtful power does not exist. Mason Co Civil Research Council v Mason Co, 343 Mich 313, 326-27; 72 NW2d 292 (1955). The Commission cannot expand its jurisdiction through its own acts or assumption of authority. Ram Broadcasting v Public Service Comm, 113 Mich App 79, 92; 317 NW2d 295 (1982). The Commission cannot re-write the Legislature's language to include new or different provisions. Hanson v Mecosta Co Rd Comm, 465 Mich 492, 501-503; 638 NW2d 396 (2002). If a Commission order conflicts with a statute, the order is void. Manufacturers Nat'l Bank v DNR, 420 Mich 128, 146; 362 NW2d 572 (1984)

Preserving Proper Consideration of Safety and Reliability by Electric Utilities is Critical

The law is clear that the safety and reliability of electric utility distribution systems is to remain paramount as distributed generation becomes more prevalent. State statutory provisions emphasize the point multiple times:

[6] Consistent with Consumers, neither is there any apparent authority to require *"standard level 1, 2, and 3 interconnection agreements"*. (See, for example R 460.901b(mm) and R 460.964)

> (1) The commission shall establish a distributed generation program by order *issued not later than 90 days after the effective date of the 2016 act that amended this section.* ***The commission may promulgate rules the commission considers necessary to implement this program. Any rules adopted regarding time limits for approval of parallel operation shall recognize reliability and safety complications including those arising from equipment saturation, use of multiple technologies, and proximity to synchronous motor loads…***
>
> ***(6) The distributed generation program created under subsection (1) shall include all of the following:***
>
> ***(a)*** Statewide uniform interconnection requirements for all eligible electric generators. The ***interconnection requirements shall be designed to protect electric utility workers and equipment and the general public.***
>
> ***(b) . . . If necessary, to promote reliability or safety, the commission may promulgate rules that require the use of inverters that perform specific automated grid-balancing functions to integrate distributed generation onto the electric grid.*** Inverters that interconnect distributed generation resources may be owned and operated by electric utilities. Both of the following must be completed before the equipment is operated in parallel with the distribution system of the utility:
>
> (i) ***Utility testing and approval of interconnection***, including all metering.
>
> (ii) Execution of a parallel operating agreement. (Emphasis added). (MCL 460.1173; emphasis added)
>
> and
>
> *The commission shall establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities.* The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations. ***The standards shall be consistent with generally accepted industry practices and guidelines and shall be established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public***. The merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery. (MCL 460.10e(3); emphasis added).

The electric grid, and the customers who depend on it, are very sensitive to even small changes in system operation. Voltage levels and other power quality characteristics need to be maintained within a narrow band at all times. It is critical that the reverse power flow from interconnected generation exports to the grid be maintained within the tight limits of the distribution equipment on the grid side of the interconnection. Any reverse power flow above prescribed limits is called an "inadvertent export." It is also critical that any slight disturbances from potential mis-operation of distributed generation-related equipment, that could cause a higher than allowed reverse power flow, occur for only a tiny amount of time, which *under the existing rules was milliseconds*. *The newly proposed rules allow for potentially repeated inadvertent reverse power flow for up to 32 seconds.* With respect to grid equipment stability, 32 seconds is a very long time, and these power disturbances could potentially cause significant damage to grid or customer equipment such as transformers or appliances, or even cause equipment fires or arc flashes, any of which might pose safety risks to electric utility employees or the public. The inadvertent export definitions included in the revised rules are inconsistent with industry standards and practices and pose significant challenges to operating the grid safely and reliably. Accordingly, DTE requests that these definitions be removed from the rules as set forth in Exhibit A.

In order to maintain safe conditions, electric utilities as the owners and operators of their respective distribution grids, are required to *properly* study and assess the potential impacts of any customer attachment or changes to their distribution grids. These assessments have historically been performed using industry accepted screening criteria applied to each proposed interconnection. It has been recognized that the existing interconnection rules have allowed for safe and reliable interconnection and operation of distribution systems in Michigan.[7]

[7] See, for example, *"Q. Have there been any safety or reliability issues related to the DG Program? A. No, not to my knowledge. In testimony filed in this case, the Company does not raise any concerns regarding reliability of the distribution system related to solar DG systems. This is likely because the interconnection process governs the interconnection of any electric generator to the distribution grid and requires each utility to carefully assess the safety and integrity of the grid before approving an application."* (Case No. U-20836 Prefiled Direct Testimony of Dr. Laura S. Sherman p. 22 on behalf of Michigan EIBC/IEI)

Distributed energy resources and generation[8] can introduce changes to power flowing either to or from the grid and the interconnection process must permit electric utilities to carefully assess the safety and integrity of the impacts of the specific proposed interconnection before approving an application. The newly proposed rules unreasonably and unnecessarily constrain electric utilities' ability to perform a complete technical assessment by limiting the screening criteria that electric utilities can apply. Reducing the screening criteria may in some cases lead to distributed energy resources and generation installations that cannot be reliably and safely supported by the distribution grid, which in turn could result in potentially dangerous conditions. Accordingly, DTE Electric requests that the newly proposed rules allow for the incorporation of additional screening criteria in order to adequately assess safety and reliability for each individual interconnection situation.

Proper Cost Allocation and Recovery is Critical

A third concern involves the newly proposed rules determination to utilize *"fee caps" for actions and studies required by the rules* (See, for example, R 460.920, R460.926, and R 460.928) as well as *requirements to disclose through, inter alia a "Pre-application report", various proprietary and commercially valuable electric utility system information to 3rd parties for only a nominal fee ($300)* and despite the possibility it could be sensitive Critical Electric Infrastructure

[8] It is further relevant that distributed generation is comprised of an increasing variety of equipment and operators with different operational characteristics and priorities – substantially increasing the number of different circumstances to which electric utilities must respond. Newly proposed rule R 460.920 would permit innumerable other persons with varying degrees of understanding or skill to potentially change electric utility interconnection procedures based on that person's self-interest and without knowledge of, or regard for, the safety and reliability of electric utilities' electric systems. Furthermore, electric utilities control over its own property is a crucial element of the Company's property rights. [See generally, *Loretto v Teleprompter Manhattan CATV Corp*, 458 US 419, 435-36; 102 S Ct 3164; 73 L Ed 2d (1982) (holding that a New York law requiring a landlord to permit a cable television company to install cable facilities on the landlord's property constituted a taking of the landlord's property); *Kaiser Aetna v United States*, 444 US 164, 176; 100 S Ct 383; 62 L Ed 332 (1979) (a requirement that subjected a formerly private pond to public access took away the landlord's right to exclude, one of the most essential sticks in the bundle of rights that are commonly characterized as property.")]

Information (CEII) (See, for example, R460.926 and R 460.932). *The Company cannot be required to provide services without full compensation nor relinquish its property rights in proprietary business information (including but not limited to electrical system information) without just compensation.* At a minimum, these "fee caps" and mandated proprietary and commercially valuable electric utility information disclosures risk violation of the requirement that *"[t]he merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery."* (MCL 460.10e(3)) Electric utilities like DTE Electric have constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the US Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, the Michigan Constitution of 1963, art 10, § 2 provides in part, *"Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law."* These constitutional protections have been recognized and applied to public utility rates in well-established case law. See generally, <u>Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri</u>, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); <u>Federal Power Comm v Natural Gas Pipeline</u>, 315 US 575; 62 S Ct 736; 86 L Ed 1037 (1942); <u>Duquesne Light Co v Barasch</u>, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989). See also, <u>Northern Michigan Water Co v Public Service Comm,</u> 381 Mich 340; 161 NW2d 584 (1968); <u>Consumers Power Co v Public Service Comm</u>, 415 Mich 134; 327 NW2d 875 (1982); <u>ABATE v Public Service Comm</u>, 430 Mich 33; 420 NW2d 81 (1988). Such requirements must be removed from the newly proposed rules.

<u>Proper Utilization of Well Understood Commission Rules and APA Procedures is Critical</u>

An overarching Due Process concern involves the complex dispute resolution procedures set forth in the newly proposed rules which provide for "Informal Mediation", "Formal

Mediation", "Contested Cases", and "Complaints." (See generally R 460.904 and R 460.906) Informal Mediation places Commission Staff in what appears to be the role of mediator. (See R 460.904(3)) Subsequent to any Informal Mediation, Formal Mediation appears to be required.[9] Formal Mediation requires multiple submissions to the Commission and involves an Administrative Law Judge (ALJ) as mediator with *"assistance from commission staff."* (R 460.906(1)(a)-(f)) And the newly proposed rules also appear to preserve the potential filing of a *"contested case proceeding"* pursuant to the Rules of Practice and Procedure Before the Commission (See generally, R 792.10401 et. seq.; See specific reference in newly proposed rule R 460.906(1)(f) to R 792.10415 "General Provisions" addressing a "contested case proceeding"). The newly proposed rules, however, also appear to preserve the right to file a complaint (addressed generally in R 792.10439 – R792.10446 of the Rules of Practice and Procedure Before the Commission). It is also worthy of note that Staff has historically participated in contested cases and complaints[10] as a party[11], so it is unclear under the newly proposed rules how Staff would reconcile its roles as mediator, provider of *"assistance"* to an ALJ mediator, and potential contested case party. Thus, the newly proposed rules contemplate the potential for multiple forms of addressing disputes that are not mutually exclusive, lack clear adherence to the Administrative Procedures Act MCL 24.201 et. seq. and the existing Rules of Practice and Procedure Before the Commission R 792.10401 et. seq., and otherwise do not clearly ensure adequate Due Process.

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[9] "*(1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904,* ***the parties shall then attempt to resolve the dispute*** *in the following manner:…"* (R 460.906(1))(emphasis added)

[10] A "complaint" *is* also a "contested case" but a "contested case" may not also be a "complaint."

[11] It is noteworthy that the Rules of Practice and Procedure Before the Commission R 792.10402(f) identifies Commission Staff as a *"Party" "…in any proceeding in which the staff participates."* It is therefore unclear how Staff can be expected to engage in the roles set forth in the newly proposed rules consistent with Due Process, the APA, or the existing Rules of Practice and Procedure Before the Commission.

DTE Electric and others have Due Process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right to fair and just treatment in MPSC proceedings: *"No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed."* Michigan Const 1963, art 1, § 17. In addition, In re Public Service Commission Guidelines for Transactions Between Affiliates, 252 Mich App 254, 267; 652 NW2d 1 (2002) confirms that adherence to the Administrative Procedures Act is critical:

> *"Invoking the public interest and the need for policy that is responsive to a changing industry, the PSC eschewed the procedural mandates of the APA in favor of its own course of action . . . While we do not doubt the PSC's legitimate concerns . . . the process utilized by the PSC constituted a rather heavy-handed rebuke of established APA procedures, and, accordingly, we are compelled to invalidate that process" (252 Mich App at 267-68).*

Many Additional Modifications to the Newly Proposed Rules are Required

As explained generally above as well as in prior pleadings submitted by the Company and other state electric utilities in this and other dockets, there are several significant overarching considerations (in addition to more specific concerns found throughout the details of the 49-pages of newly proposed rules) that must be addressed and remediated prior to formal adoption of a final rule on these topics. Attached as Exhibit A is a redlined markup that addresses the concerns described herein (as well as other more technical concerns) that must be addressed to begin to align the newly proposed rules with existing law, procedure, and good utility practice.

Respectfully Submitted,

DTE ELECTRIC COMPANY

Dated: June 27, 2022

Exhibit A

DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.

Rule 1a. As used in these rules:

(a) “AC” means alternating current at 60 Hertz.

(b) “Affected system” means another electric utility’s distribution system, a municipal electric utility’s distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.

(c) “Affiliate” means that term as defined in R 460.10102(1)(a).

~~(d) “Aggregate capacity” or “aggregate generation capacity” means the aggregated ongoing operating capacities of all DERs across multiple points of common coupling, within a defined portion of the distribution system.~~

(e) “Alternative electric supplier” means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

Commented [A1]: Nothing in this set of rules allows for the review of transient issues, like flicker, harmonics, transient over voltage, power fluctuations, or other dynamic events as well as destruction of customer equipment, ferro-resonance in transformers, VFDs and potential fires. Finally, transients can lead to mass inverter tripping and Bulk Electrical System impacts which have been observed in other states and countries.

Commented [A2]: Concern: Definition duplicative and defined in such a way to have no useful meaning or bounds.

Solution: Existing nameplate capacity and export capacity definitions are sufficient to identify what value is intended.

Exhibit A

(f) “Alternative electric supplier distributed generation program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(g) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(h) “Applicant” means the person or entity, other than an electric utility, submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. ~~An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.~~

(i) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(j) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(k) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding electric utility holidays and any day in which electric service is interrupted for 10% or more of an electric utility’s customers. A list of electric utility holidays shall be provided in the electric utility’s interconnection procedures.

(l) “Calendar day” means every day including Saturdays, Sundays, and holidays.

(m) “Certified” means ~~an~~ inverter-based ~~system~~ hardware has met published performance requirements ~~acceptable safety and reliability standards~~ by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 September 28, 2021 edition except that prior to January 1, 2023, inverter-based systems which conform to the UL 1741SA September 7, 2016 edition are acceptable.

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

(o) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018 and IEEE1547.1-2020. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(p) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(q) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(r) “DC” means “direct current.”

(s) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of ~~exporting active power~~ injecting power and energy to a distribution system.

(t) “Distributed generation program” means the distributed generation program approved by the commission and included in an electric utility’s tariff pursuant to section

Commented [A3]: Concern: the restrictions on electric utilities are overly broad and conflicts with utilities responsibility to maintain the grid, safety, and reliability.

Example: Substation backup batteries to provide energy storage are connected to the distribution system and are not temporary. As written would these be subject to interconnection applications? Would NWA projects need interconnection applications? Is the commission expecting NWA’s to be solely screened/studied based on their potential operating capability, or based on their specific function as a distribution asset?

Solution: striking of the provision provides the most flexibility in ensuring electric utilities maintain grid safety and reliability. Any project connected by the electric utility is already subject to commission review as the regulator of the electric utility.

Commented [A4]: There should be no expectation to provide 24 hour support. This should be limited to standard hours of business and posted in procedures.

Commented [A5]: Concern: “Certified” is not restricted to inverter-based systems. Also, the UL and IEEE certifications apply to safety and reliability of the specific device under normal operation and expected utility events (outages, transients etc.) and does not certify that the device will not cause safety or reliability events on the distribution system or is being used properly. The interconnection review is what is intended to ensure that the device will not result in abnormal electrical gird behavior.

Example: A certified inverter with a power limited setting is capable of creating over voltage on the electrical system without conflicting with the certification if the power limiting setting is based on the inverter connection point instead of a gird limitation.

Solution: “an inverter-based system” should be replaced with “a component” and “Utility review of certified devices should be limited to a review of the safety and reliability of the component’s impact on other the electrical grid.” Should be added for clarity.

Commented [A6]: Concern: IEEE1547.1-2020 is the testing requirement

Commented [A7]: Concern: Definition is not consistent with other industry standards which may create confusion and conflict with future standards.

Commented [A8]: Concern: Without this change, DER that can supply reactive power are excluded.

6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(u) “Distribution system” means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(v) “Distribution upgrades” mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER’s connection to the distribution system.

(w) “Electric utility” means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, “electric utility” includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) “Electrically coincident” means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades, DER site upgrades, or some combination of both distribution and DER site upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

(y) “Electrically remote” means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) “Eligible electric generator” means a methane digester or renewable energy system with a generation capacity limited to a customer’s electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) “Energy storage device” means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

(bb) “Export capacity” ~~means the maximum possible simultaneous generation of the DER, and is calculated as the maximum amount of export as permitted by limiting the amount of the DER’s export at the point of common coupling.~~ *means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means defined by the utility.*

(cc) “Facilities study” means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) “Fast track” means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) “Force majeure event” means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause

Commented [A9]: **Concern:** as originally defined this does not consider the impact to the operation of other DER or the ability of DER to coordinate to resolve distribution system constraints.

Example: Combined fault current contribution of two new DER’s may exceed system constraints, modification of one or both DER’s may be necessary or be the most cost effective option to resolve the issue as opposed to distribution upgrades.

Solution: Add “…, DER site upgrades, or combination of both distribution and DER site upgrades…”

Commented [A10]: **Concern:** Not consistent with industry definitions

Example/Solution: US DOE sponsored BATRIES definition “means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means” adding for clarity “as defined in procedures by the electric utility or otherwise mutually agreed within an interconnection agreement”

Commented [A11]: **Concern:** Not consistent with industry definitions

Example/Solution: US DOE sponsor BATRIES definition “means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means” adding for clarity “as defined in procedures by the electric utility or otherwise mutually agreed within an interconnection agreement”

Document is available for download at
Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage - BATRIES (energystorageinterconnection.org)

https://energystorageinterconnection.org/resources/batries-toolkit/

beyond a party's control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) "Full retail rate" means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

~~(gg) "Generating capacity" means the maximum nameplate rating of a DER in alternating current, except that where this capacity is limited by any of the methods of limiting electrical export, generating capacity shall be the net capacity as limited though the use of such methods not including inadvertent export.~~

(hh) "Good standing" means an applicant has paid in full all ~~undisputed~~ bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

(ii) "Governmental authority" means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(jj) "GPS" means global positioning system.

(kk) "Grid network" means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer.

(ll) "High voltage distribution" means those parts of a distribution system that operate within a voltage range specified in the electric utility's interconnection procedures. For purposes of these rules, the term "subtransmission" means the same as high voltage distribution.

(mm) "IEEE" means I~~i~~nstitute of E~~e~~lectrical and E~~e~~lectronics E~~e~~ngineers.

(nn) "IEEE 1547-2018" means "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as adopted by reference in R 460.902.

(oo) "IEEE 1547.1-2020" means IEEE "Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces," as adopted by reference in R 460.902.

(pp) "Inadvertent export" ~~means the potential condition in which a normally non-exporting or limited-exporting DER experiences an unscheduled export that does not exceed limitations in terms of magnitude or duration as specified in UL 1741 CRD for PCS.~~ *means the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, due to fluctuations in load-following behavior.*

(qq) "Independent system operator" means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(rr) "Initial review" means the fast track initial review screens described in R 460.946.

Commented [A12]: Concern: creates confusion with export capacity.

Example: For purposes of providing nameplate capacity in a pre-application report, is a 5 MW generator that is limited to 1 MW of grid export but connected to a facility with a minimum load of 4 MW a 1 MW or a 5 MW generator?

Solution: Existing nameplate capacity and export capacity definitions are sufficient to identify what value is intended.

Commented [A13]: Concern: creates incentive to dispute bills

Solution: strike "Undisputed"

Commented [A14]: IEEE 519 is missing from the definitions

if storage is going to be included https://sagroups.ieee.org/scc21/standards/2030-2-1-2019/ needs to be included.

Commented [A15]: Concern: In addition to providing for normal fluctuations this allows for potentially damaging flows to the distribution system as UL 1741 only has scope of the DER equipment and not the interconnection.

Example: A large DER offsetting a large load, experiences a loss of load resulting in the DER reaching its UL limit of 110% (132V) at the point of interconnection, utility distribution equipment which was compensating for low voltage prior to the inadvertent export event was set for 5% raise taking the distribution system to 115% or 138V, which would not be allowed to exist for 30 seconds by UL 1741 or any other industry standard.

Solution: US DOE sponsored BATIERS definition "*means the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, due to fluctuations in load-following behavior.* "

(ss) “Interconnection” means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(tt) “Interconnection agreement” means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement, or amendments, shall estimate~~specify~~ timelines, provide non-binding cost estimates, and require payment(s) in advance to the electric utility, or timely payment in advance of milestones acceptable to the electric utility, ~~payment milestones~~ for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, controls, settings, procurement, installation, and construction requirements associated with installation of the DER. ~~Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.~~

(uu) “Interconnection coordinator” means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(vv) “Interconnection customer” means the person or entity, which ~~may~~ does not include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(ww) “Interconnection facilities” mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(xx) “Interconnection procedures” mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

(yy) “Interconnection study agreement” means an agreement between an applicant and an electric utility for the electric utility to study a proposed DER.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) “kW” means kilowatt.

(b) “kWac” means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) “kWh” means kilowatt-hours.

(d) “Legacy net metering program” means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) “Level 1” means a project using certified equipment with a nameplate capacity ~~project~~ of 20 kWac or less.

(f) “Level 2” means a project using certified equipment with a nameplate capacity ~~project~~ of greater than 20 kWac and not more than 150 kWac.

(g) “Level 3” means a project of 150 kWac or less that is not using certified equipment, or a project greater than 150 kWac and not more than 550 kWac.

Commented [A16]: Concern: Agreements missing scope items and combining time limited construction items with ongoing requirement in the interconnection agreement.

Example: Payment prior to construction is needed to limit liability transfer. Control settings need to be added.

Solution: Second sentence as modified “Where construction of interconnection facilities or distribution upgrades are necessary, the agreement, or amendments, shall estimate timelines, provide non-binding cost estimates, and require payment in advance to the electric utility for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, controls, settings, procurement, installation, and construction requirements associated with installation of the DER.”

Commented [A17]: Concern: Clarification that control settings should be included within the agreement as they are important part of the ongoing DER operation.

Example: if control settings are used to eliminate the need for system upgrades those settings need to be in the agreement.

Solution: added “controls, settings” to language.

Commented [A18]: Concern: the restrictions on electric utilities are overly broad,

Example: Substation control (non-system storage) backup batteries provide ability to operate switching equipment and restore the system during outages. As written would these be subject to interconnection applications?

Solution: striking of the provision provides the most flexibility in ensuring electric utilities maintain grid safety and reliability. Any project connected by the electric utility is already subject to commission review as the regulator of the electric utility.

Commented [A19]: Concern: Certification applies only to the equipment response to variations on the electrical system, not the potential system impact from the DER equipment on the system.

Example: An UL 1741 certified inverter can ensure that voltage remains at 110% at the terminals of the device but can’t prevent further voltage rise from other devices on the electrical system.

Solution: definitions adjusted to reflect proper use of certification.

(h) "Level 4" means a project of greater than 550 kWac and not more than 1 MWac.
(i) "Level 5" means a project of greater than 1 MWac.
(j) "Level 4 and 5 interconnection agreement" means an interconnection agreement applicable to level 4 and 5 interconnection applications.
(k) "Limited export" means the exporting capability of a DER whose ~~generating~~ nameplate capacity is limited by means accepted by the electric utility.~~the use of any configuration or operating mode~~.
(l) "Low voltage distribution" means those parts of a distribution system that operate with a voltage range specified in the electric utility's interconnection procedures.
(m) "Mainline" means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.
(n) "Material modification" means a modification to the DER nameplate rating~~generating capacity~~, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. ~~Replacing a component with another component that has near-identical characteristics does not constitute a material modification.~~ For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:
(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.
(ii) The cost, timing, or design of any other application.
(iii) The electric utility's distribution system or an affected system.
(iv) The safety or reliability of the distribution system.
(o) "Methane digester" means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.
(p) "Modified net metering" means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system during a billing period or time-of-use pricing period.
(q) "MW" means megawatt.
(r) "MWac" means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.
(s) "Nameplate capacity" ~~means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation~~. *Nameplate Rating means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.*
(t) "Nameplate rating" means all of the following at which a DER is capable of sustained operation:
(i) Nominal voltage (V).
(ii) Current (A).
(iii) Maximum active power (kWac).
(iv) Apparent power (kVA).
(v) Reactive power (kvar).

Commented [A20]: Concern: some configuration or operating modes are not sufficient to ensure limited export.

Example: A device that fails to maintain export limits during software or firmware updates or that that can be changed at any time due to poor implementation of access controls or cyber security would be an example of an unacceptable operating mode for limited export.

Solution: language as modified

Commented [A21]: Concern: near identical is not defined and is subject to a wide range of interpretation.

Example: does 'near identical' apply to the number or the severity of the change in characteristics? An inverter that is the same nameplate size and voltage ratings, but has a 200% vs. a 110% nameplate fault current contribution may be near identical to an interconnection customer. This would not be 'near identical' from an electrical system perspective.

Solution: strike language.

Commented [A22]: Concern: nameplate capacity is the appropriate term here. Power export is one factor out of many that need to be considered when assessing the impact to system reliability and power quality.

Example: Replacing a 1 MW inverter with a 2 MW inverter control limited to 1 MW is not equivalent from an inadvertent export or fault current perspective and creates new risk that would need to be studied.

Solution: Use of nameplate capacity in place of nameplate capacity.

Commented [A23]: Concern: definition is not consistent with industry:

Example/Solution: US DOE sponsored BATIERS definition "Nameplate Rating means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means."

(u) "Nationally recognized testing laboratory" means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.

(v) "Network protector" means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs.

(w) "Non-export track" means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility's distribution system, as described in R 460.942.

~~(x) "Ongoing operating capacity" means the actual simultaneous generating capacity, taking into account the operational differences of load offset and export. If the contribution of energy storage to the total contribution is limited by programing of the maximum active power output, use of a power control system, use of a power relay, or some other mutually agreed upon, on-site limiting element, only the capacity that is designed to inject electricity to the utility's distribution system, other than inadvertent exports and fault contribution, will be used within certain technical screens and evaluations.~~

(y) "Parallel operation" means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.

(z) "Party" or "parties" means an electric utility, applicant, or interconnection customer.

(aa) "Point of common coupling" means the point where the DER connects with the electric utility's distribution system.

~~(bb) "Power control system" means systems or devices which electronically limit or control steady state currents to a programmable limit and certified under UL 1741 CRD for PCS by a nationally recognized testing laboratory.~~ ***Power Control System*** *or PCS means systems or devices which electronically limit or control steady state current to a programmable limit.*

(cc) "Radial supply" means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.

(dd) "Readily available" means no creation of data is required, and little or no computation or analysis of data is required.

~~(ee) "Reasonable efforts" mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.~~

(ff) "Regional transmission operator" 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, expansion, operation, and use on a regional and interregional basis.

(gg) "Renewable energy credit" means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.

(hh) "Renewable energy resource" means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(ii) "Renewable energy system" means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

Commented [A24]: Concern: Duplicative, Conflicts with other definitions.

Example/Solutions: this can be more effectively accomplished by making those inclusions/exclusions within the applicable screens.

Commented [A25]: Concern: definition is not consistent with industry:

Example/Solution: US DOE sponsored BATIERS definition "***Power Control System*** *or PCS means systems or devices which electronically limit or control steady state current to a programmable limit.*

Commented [A26]: Unnecessary.

(jj) “Secondary network” means those areas of a distribution system that operate at a secondary voltage level and are networked.

(kk) “Site” means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.

(ll) “Spot network” means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.

~~(mm) “Standard level 1, 2, and 3 interconnection agreement” means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications. A cover sheet including modifications to address any special operating conditions may be added.~~

(nn) “Study track” means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.

(oo) “Supplemental review” means the fast track supplemental review screens described in R 460.950.

(pp) “System impact study” means a study to identify and describe the impacts to the electric utility’s distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility’s distribution system. A system impact study also identifies affected systems.

(qq) “Temporary DER” means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.

(rr) “True net metering” means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility’s distribution system, during a billing period or time-of-use pricing period.

(ss) “UL” means underwriters laboratory.

(tt) “UL 1741” means the September 28, 2021 edition of “Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources,” as adopted by reference in R 460.902.

(uu) "UL 1741 CRD for PCS" means the Certification Requirement Decision for Power Control Systems for the standard titled Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, March 8, 2019, as adopted by reference in R 460.902(b).

R 460.902 Adoption of standards by reference.

Rule 2. (1) The standards specified in these rules are adopted by reference as follows:

(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, September 28, 2021 edition, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/ProductDetail.aspx?productId=UL1741 at a cost of $798.00 at the time of adoption of these rules.

(b) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, January 28, 2010 edition, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/ProductDetail.aspx?productId=UL1741 at a cost of $716.00 at the time of adoption of these rules.

(c) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.

(d) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.

(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.

(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.

(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.

(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.

(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.

Rule 4. (1) The parties ~~shall~~ may attempt to resolve ~~all~~ disputes arising out of the interconnection process~~, as defined by R 460.901a through R 460.992, according to the provisions of this rule~~.

~~(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.~~

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties may~~shall~~ discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use commercially reasonable~~best~~ efforts to resolve the dispute.

~~(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.~~

~~(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.~~

~~R 460.906 Formal mediation.~~
~~Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:~~
~~(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party's possession on which the party intends to rely to support the party's position.~~
~~(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party's email address and file the notice with the commission.~~
~~(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.~~
~~(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.~~
~~(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.~~
~~(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.~~
(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation ~~or formal mediation~~ pursuant to these rules.
(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Timelines for electric utilities serving fewer than 1,000,000 in-state customers.
Rule 8. An electric utility serving fewer than 1,000,000 in-state customers shall have an additional 10 business days to comply with the timelines in R 460.911 to R 460.1026. This rule does not apply to applicants or interconnection customers.

R 460.910 Waivers.
Rule 10. An electric utility or~~,~~ ~~customer,~~ alternative electric supplier~~, applicant, or interconnection customer~~ may request~~apply to the commission for~~ a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission

may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest. No waiver is necessary or required with respect to an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.
Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules. ~~The electric utility shall complete work on any interconnection study agreement executed prior to the effective date of these rules pursuant to the terms and conditions of that interconnection study agreement. Any new studies or other additional work must be completed pursuant to these rules.~~ Existing applications that are inactive, become subject to these rules once either party perform an action to progress a project under these rules. An electric utility or an alternative electric supplier shall not restrict access to interconnection for level 1, level 2, and level 3 DERs that are not participants in the legacy net metering or distributed generation programs.

R 460.920 Electric utility interconnection procedures.
Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms within 120~~30~~ business days of the effective date of these rules.
(2) The commission shall issue its order approving or~~,~~ rejecting~~, or modifying~~ the proposed interconnection procedures and forms within 360 calendar days of the effective date of these rules. ~~If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another person in the proceeding or modify and accept the procedures and forms proposed by the electric utility.~~
(3) Until the commission accepts~~, rejects, or modifies~~ all of an electric utility's interconnection procedures and forms, the electric utility may use the proposed interconnection procedures and forms when processing interconnection applications. ~~with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms unless the commission approves different fees pursuant to R 460.926(4).~~

Commented [A27]: Concern: Need to resolve conflicts between existing projects and the new rules.

Example: It is unclear if a project not moving forward under the old rules should impact projects under the new rules.

Solution: New language: "Existing applications where no study or work is active, become subject to these rules once either party performs an action to progress a project under these rules."

Commented [A28]: Concern: Need to resolve conflicts between existing projects and the new rules.

Example: It is unclear if a project not moving forward under the old rules should impact projects under the new rules.

Solution: New language: "Existing applications that are inactive, become subject to these rules once either party perform an action to progress a project under these rules."

Commented [A29]: Concern: The changes adopted after the initial deadline are significant and invalidate significant work performed in the development of the procedures.

Example: The initial procedures stakeholder meeting highlights many gaps between draft procedures and current rules.

Solution: Additional time to make the necessary adjustments pending the final version of the rules.

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, describe~~include~~ all of the electric utility's requirements for the following:

(a) All necessary applications and~~,~~ forms~~, and relevant template agreements~~.

~~(b) A schedule of all applicable fixed fees and fee caps.~~The interconnection application fees that will recover the electric utility's costs as provided for in R 460.926 and R 460.928.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Acceptable methods or standards for power-limited export DERs in compliance with allowances in R 460.980.

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

~~(m) Details describing how an energy storage device may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.~~

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.

(o) Examples of modifications that are not material modifications.

~~(p) The procedure for performing a material modification review to determine if a modification is material.~~

(q) Any required terms and conditions which must be specified in the general liability insurance for level 3, 4, and 5 projects.

(r) A list of the electric utility's holidays.

(s) If an electric utility uses an alternative process pursuant to R 460.956, a description of that process.

(6) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable

deadlines under these rules until the matter is resolved. ~~An electric utility shall obtain commission approval to revise its interconnection procedures.~~

R 460.922 Online applications and electronic submission.

Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.

(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:

(a) These rules and interconnection procedures in an electronically searchable format.

(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.

(c) Sample documents including, at a minimum, a 1-line diagram with required labels.

(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.

(e) Directions for the submission of applications.

R 460.924 Communications.

Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process. The interconnection coordinator ~~utility~~ is not responsible for~~to~~ providing~~e~~ repeated training to an applicant~~te~~, or ongoing support for how to properly apply for interconnection.

(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.

(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Fees.

Rule 26. (1) After the effective date of these rules, all electric utility fees for the pre-application report, application, the non-export track and the fast track shall be the electric utility's actual documented fully embedded costs with a return at the electric utility's authorized rate of return on capital expenses and without markup on operations and maintenance expense. Information that the electric utility chooses to disclose in a pre-application report or otherwise shall be priced at the market value of such information as determined by the electric utility. The customer shall pay all interconnection costs.

Commented [A30]: **Concern:** Reasonableness could use some supporting language.

Example: Reasonable support for an interconnection customer that has never been through the process is materially different than the support that should be provided to an applicant that has attempted hundreds of previous applications.

Solution: additional language to clarify reasonable "The interconnection coordinator is not responsible for providing repeated training to an applicant's employees, or ongoing support for how to properly apply for interconnection once reasonable assistance has been given."

the~~established as listed in subrule (2) of this rule. Initial fees for the study track shall not exceed initial fee caps as established in subrule (3) of this rule. Fees must remain in effect until interconnection procedures are approved by the commission under R 460.920.~~ At the electric utility's option, a system impact study and a facilities study may be conducted by a qualified 3rd party engineering firm and the fee for such study or studies shall be the electric utility's actual documented cost.

(2) ~~The fee amounts for the pre-application report, non-export track, and fast track for all levels of DERs are as follows:~~
~~(a) The pre-application report fee may not exceed $300.~~
~~(b) The non-export track fee may not exceed $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.~~
~~(c) The fast track initial review fee is $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.~~
~~(d) Any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.~~
~~(3) The initial fee caps for a fast track supplemental review and the study track for all levels of DERs are as follows:~~
~~(a) The fee for a fast track supplemental review including all review screens may not exceed $1,000.~~
~~(b) The study track fee for interconnection application review and the scoping meeting may not exceed $300.~~
~~(c) The system impact study fee may not exceed $10,000.~~
~~(d) The facilities study fee may not exceed $15,000.~~
(4) Application~~The~~ fees ~~listed in subrule (2) and initial fee caps listed in subrule (3) of this rule,~~ must be displayed prominently on the electric utility's interconnection website.
~~(5) An electric utility that expects to incur costs greater than the fees listed in subrule (2) or initial fee caps listed in subrule (3) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.~~

Commented [A31]: Concern: clarification need to ensure that this is only for a review of the application form in a scoping meeting and does not substitute for application review fee for fast track or study process.

Commented [A32]: Language was written to provide clarity to written comments. In addition, the following technical concerns exist as written.

Concern: size-based fees need to be referenced to nameplate capacity. No processes exist to collect insufficient fees based on changes in use of certified or non-certified devices or where the applicant provided an undersized application.

Example a 2 MW project that proposes to proceed with a 1 MW export limit using a certified inverter. The initial review should be based on the 2 MW value and if it is identified that a non-certified inverter is used the additional $1/kWac should be collected.

Solution: Add nameplate, provide for collection of insufficient fees while in application, alternatively require that the application be withdrawn and resubmitted.

~~R 460.928 Fee and fee cap modifications.~~
~~Rule 28. (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the fees specified in R 460.926(2)(a), (b), and (c), and add any other fixed fees the electric utility considers necessary.~~
~~(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(3)(a), (b), (c), and (d), and add any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.~~
~~(3) The fixed fees must be specific to level size and be based on estimates of reasonable costs to perform the applicable service or study. The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.~~
~~(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.~~

(5) Application fees~~The fixed fees and fee caps~~ that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.

(6) Any modification of fees may not be applicable to fees already paid.

(7) An electric utility that expects to incur costs greater than its prevailing fee caps in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.930 Pre-application report request form.

Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.

(2) The pre-application report request form must include all of the following information:

(a) Project contact information, including name, address, phone number, and email address.

(b) Project location, as accurately as can be identified, which may be given by any of the following:

(i) Street address with nearby cross streets and town, county and zip code.

(ii) An aerial map with location clearly marked.

(iii) GPS coordinates.

(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.

(d) Whether the DER equipment is certified or non-certified and is any combination of the following:

(i) Solar.

(ii) Wind.

(iii) Cogeneration.

(iv) Storage.

(v) Solar with storage.

(vi) Other type of DER (must specify).

(e) Capacity of the DER types in alternating current kW, direct current kW, and kVA, and kWh for storage including existing and new.

(f) Whether the DER configuration is single or 3-phase.

(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.

(h) Whether the DER will be certified.

(i) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.

(j) Whether the location is new construction.

(k) if the coupling between generation and/or storage is A/C or D/C and if separate inverters will be used.

(l) where the site is planning on participating in market programs

Commented [A33]: Concern: Standards certify equipment performance, not interconnections

Solution: language as modified.

Commented [A34]: Concern: These questions help provide clarification about the expected operation of the DER.

R 460.932 Pre-application report.

Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.

(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.

(3) At the electric utility's option, and upon full payment in advance of the market value as determined by the electric utility, of such information, t~~T~~he pre-application report may~~must~~ include all of the following information:

(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.

(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.

(f) Nominal distribution circuit voltage at the proposed point of common coupling.

(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.

(h) Approximate circuit distance between the proposed point of common coupling and the substation.

(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.

(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.

(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.

(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.

(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.

(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.

(o) Whether or not the area has been identified as having a prior affected system.

(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available.~~ The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. ~~An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.

(6) An electric utility shall provide the data required in the pre-application report to the applicant within 20 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant. In no event shall the electric utility be required to provide information prior to full payment in advance, or that the electric utility in good faith determines to be Critical Electric Infrastructure Information (CEII) or subject to National Electric Reliability Council Critical Infrastructure Protection (NERC CIP).

Commented [A35]: **Concern:** Costs of, and risk of, providing detailed system information can change rapidly and it is necessary to ensure that utilities can take reasonable actions to protect the security of the electrical system.

Example: Cybersecurity teams identify critical circuit information available on the web linked to pre-application reports.

Solution: The electrical utility should be able to respond to real time information and make determinations about what level of information protection is required to maintain grid security based real world conditions.

R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.

(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:

(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.

(b) An enforceable option to purchase or acquire a leasehold site for this purpose.

(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.

(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature and contact information on the application.

(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.

Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.

(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.

(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.

(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer

licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.

(5) For interconnection applications with proposed DERs that fall into levels 4 and 5, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.

(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric utility has received the interconnection application, the application attachments, and payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.

(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.

(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the non-export track, fast track, or study track.

(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

~~(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.~~

~~(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.~~

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a publicly available interconnection list, which is available in a sortable spreadsheet format. The sortable spreadsheet must be provided to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no

Commented [A36]: **Concern:** the restrictions on electric utilities are overly broad.

Example: Substation backup batteries provide energy storage are connected to the distribution system and are not temporary. As written would these be subject to interconnection applications? Would NWA projects need interconnection applications? Is the commission expecting NWA's to be studied based solely on their potential operating capability as an interconnection or based on their specific function as a distribution asset?

Solution: striking of the provision provides the most flexibility in ensuring electric utilities maintain grid safety and reliability. Any project connected by the electric utility is already subject to commission review as the regulator of the electric utility.

changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.

(2) The public interconnection list must include all of the following:

(a) An application identifier.

(b) The date that the electric utility received the application.

(c) The date that the electric utility considered the application to be complete and conforming.

(d) Whether the application is on the non-export track, fast track, or study track.

(e) The proposed DER nameplate capacity.

(f) The proposed DER interconnection size level.

(g) The DER technology type.

(h) The county and township in which the proposed point of common coupling will be located.

(i) The current status of the application's progress in the interconnection process.

(j) The labels, names, or identifiers of the distribution circuit and substation.

(3) In no event shall the electric utility be required to provide information prior to full payment in advance or that the electric utility in good faith determines to be Critical Electric Infrastructure Information (CEII) or subject to National Electric Reliability Council Critical Infrastructure Protection (NERC CIP).

R 460.942 Non-export track review.

Rule 42. (1) Interconnection applications for DERs that agree in writing to install and properly operate utility approved controls that will ~~limit~~ prevent injection of electric energy into an electric utility's distribution system are eligible for evaluation under the non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

(2) ~~Subject to review and approval by the commission, an~~ An electric utility may limit the eligibility of the non-export track in its interconnection procedures based on the characteristics of its distribution system.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility interconnection coordinator for assistance in determining whether a non-export track review will be sufficient or the study track is necessary. The electric utility shall provide the applicant reasonable assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the ~~initial~~ review screens specified in the electric utility's interconnection procedures, including evaluating the potential for power quality or operational -impacts to other customers ~~power quality~~ and utility assets, and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require interconnection facilities, distribution upgrades, further study, or application modifications, subject to subsection (7).

Commented [A37]: Concern: This is a rapidly evolving area of distribution systems.

Example: This list would provide an adversary a list of circuits that could be impacted based on if a specific technology has been compromised.

Solution: Electric utilities should be able to respond to new information as it becomes available to the industry.

Commented [A38]: Concern: Non-export is different than limited export and this clarifies that limited export is processed under the applicable fast track or study screens.

Example: A project with 2 MW nameplate limited to 1 MW of export should be processed under the appropriate track under the remainder of these rules, not non-export.

Solution: Added clarification that the method to prevent export must be approved by the utility to be processed as a non-export track.

Commented [A39]: Concern: This section is specifically to allow for a non-export interconnection, not limited export. The potential impacts of large generation hidden behind large load would not be adequately addressed by the existing screens.

Example: a non-export project would default to level 1 in the rules as written, which would exclude most screens. The interaction of the DER with other distribution devices such as capacitors and regulators is important to coordinate and would not be covered by the screens listed.

Solution: Add language to ensure that non-export specific criteria can be used and any issues identified could be addressed.

(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install and, in order to properly do so, may require site walkdowns to identify appropriate locations for disconnects, metering, and other equipment. Applicant shall schedule such walkdowns at at a reasonable, mutually agreeable time.~~within 20 business days of the applicant being notified~~. Within 10 business days of receiving the equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.

(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business days that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (4) of this rule.

(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.

(6) If~~When~~ an applicant changes electric utility tariff service or from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application to permit proper evaluation of equipment and operational requirements.

(7) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.944 Fast track applicability.

Rule 44. (1) Level 1, level 2, level 3, and level 4 applications and level 5 applications as large as 1~~5~~ MWac in which the DER will not ~~is not proposing to~~ interconnect with the electric utility's high voltage distribution system are eligible for the fast track. Projects using an acceptable method for limited export shall be eligible for fast track, the Level of

Commented [A40]: **Concern:** Non-export configurations vary significantly and may be part of customer industrial process and operations. Site visits or additional configuration information is typically needed to ensure alignment in the placement of equipment and future configurations or facility upgrades.

Example: Siting protective equipment such as relay and disconnect equipment can often be made simpler by coordinating on site with customers.

Solution: Updated language to include added options for site walkdowns and adjust timelines to allow for site visit coordination.

Commented [A41]: **Concern:** Additional clarification that moving to an export tariff will require re-evaluation.

Example/Solution: Adjust language to ensure that its clear that a new evaluation will be needed if the export level is changed.

Commented [A42]: **Concern:** 5 MWac exceeds utility operating criteria and exceeds maximum ratings of almost all 4.8kV circuits.

Solution: Lower threshold should be used to reflect realistic opportunity to pass fast track screens.

Commented [A43]: **Concern**: Fast Track applicability should be based on an agreed point of interconnection for study, not an initially proposed one that may be infeasible.

Example: A 5 MW project proposing to interconnect to a 4.8kV distribution area, but with a 40kV line on site should be directed to study at the 40kV point of interconnection vs. the 4.8kV location.

Solution: modified language to clarify the actual point of interconnection.

the project shall be determined by the nameplate rating. ~~Applications that provide for the use of an energy storage device so the export of power meets the requirements of level 1, level 2, level 3, level 4 or level 5 as large as 5 MWac in which the applicant is not proposing to interconnect the DER with the electric utility's high voltage distribution system are also eligible for the fast track.~~

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may, at its discretion, aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling~~.~~

(5) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (4) of this rule. An electric utility may add additional details to each of these screens, or additional screens in the interconnection procedures.

(2) The electric utility may waive application of 1, some, or all of the initial review screens.

(3) Within 10 business days after an electric utility receives a complete and conforming level 1 or level 2 application and associated payment, or within 20 business days after an electric utility receives a complete and conforming level 3, level 4, or level 5 application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (2) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens, subject to subsection (8).

(4) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. ~~The electric utility shall consider 100% of applicable loading, if~~

Commented [A44]: Concern: The applicability of nameplate or export capacity varies by screen. Nameplate should be the default. Use of export capacity should be considered as applicable to ensure the safety and reliability of electrical grid and other equipment not covered by certification.

Solution: Language as modified and supported by the Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage

Commented [A45]: Concern: Multiple points of common coupling should only be used when doing still allows for accurate screening.

Example: A customer with a second service may or may not have its generation aggregated based on if the services are at the same voltage level and electrically proximate (physically close without operating equipment between) and other factors.

Solution: made it clear that the electric utility would make the determination to aggregate based on its assessment of how the generation would interact across the various points of interconnection.

Commented [A46]: Concern: While modification of these screens in procedures is a good step. It is critical that as the electrical utility be able to place new screens that account for known system conditions or previously identified issues to be address during the screening process instead of at, or after commissioning. Additionally, emerging technology or higher levels of DER penetration may require new screens to adequately assess system impacts.

Example: FERC SGIP, which most of these screens are based on, specifically includes provision 2.2.1.10 that protects asset owners in the event that an issue requiring action by the electrical utility is required. For example, for a customer with a dedicated 25kVA transformer installing a 40kW PV system would pass the screens because the secondary is not shared, while clearly potentially overloading electrical utility equipment.

Solution: Adjust language to allow for additional screens to be added via procedures.

~~available, instead of 15% of line section peak load for level 1 and level 2 DER. In the event daytime loading data is not available, the data must be collected by January December 2023~~ for electric utilities with more than 1,000,000 customers in this state, or by a date specified in interconnection procedures approved by the commission for electric utilities with fewer than 1,000,000 customers in this state, and shall not consider as part of the aggregate generation, for purposes of this screen, DER capacity known to be already reflected in the minimum load data. ~~This screen does not apply to level 1 and level 2 non-export DER applications.~~

(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must either implement a non-sell back protection scheme approved by the electric utility to not exceed the customer load or utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's protectors maximum load or 50 kWac.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling. ~~This screen does not apply to level 1 applications.~~

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers. ~~This screen does not apply to level 1 applications~~.

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen
3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER ~~export~~ nameplate capacity, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

Commented [A47]: Concern: Time is needed to collect this data and the adoption of the rules may not make this date feasible. Unclear if this is a utility interconnection or planning activity?

Solution: Remove requirement or extend date of requirement to accurately collect information once rules go into effect.

Commented [A48]: Concern: This screen should apply to level 1 and level 2 DER's where existing aggregated generation already exceeds 15% of line section.

Example: a new subdivision is built as a net zero community. While each interconnection may be level 1 or 2 the combined nameplate capacity will likely exceed 100% of the daytime for that line section.

Solution: Apply screen to level 1 and level 2.

Commented [A49]: Concern: Limit should be based on the rating of the protective device not the entire network.

Example: 5% of a networks load may be larger than the rating of an individual network protector and cause unintended operation.

Solution: added protector for clarification.

Commented [A50]: Concern: This screen should apply to level 1 DER's where existing aggregated fault contribution capability exceeds 10% of the system capability.

Example: a new subdivision is built as a net zero community. While each interconnection may be level 1 the combined fault current contribution may exceed 10%.

Solution: Apply screen to level 1.

Commented [A51]: Concern: This screen should apply to level 1 DER's where existing aggregated fault contribution capability may cause equipment on the system to exceed 87.5% of the system capability.

Example: a new subdivision is built as a net zero community. While each interconnection may be level 1 the combined fault current contribution may cause equipment ...

Commented [A52]: Removed because of aggregate contribution is equivalent to a larger DER

Commented [A53]: Concern: potential voltage issues during inadvertent export should receive supplemental review.

Example: A 40kW system with a net export limit of 20kWac would cause a 5.6V raise during inadvertent export. This could place voltage in an immediate action window. ...

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the aggregate DER's nameplate rating beyond that regulator must be less than 250 kWac. ~~This screen does not include substation voltage regulators.~~

(k) No construction of facilities by the electric utility on its own system shall be required to accommodate the DER.

(l) With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed 3%.

(5) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection application must proceed under R 460.962.

(6) If the proposed interconnection fails any of the initial review screens, or the interconnection does not comply with the applied for tariff, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (3) of this rule.

(d) Withdraw the interconnection application.

(7) If the applicant does not select a course of action under subrule (6) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

(8) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or

Commented [A54]: Concern: Not all line or substation distribution regulators are capable of bi-directional operation and this screen doesn't not address substation regulation that would be impacted or aggregate impacts.

Example: A small rural substation with 1.5 MVA capacity is regulated by uni-directional line regulators inside the substation. A 250kW DER or multiple ones, would potentially cause failure or mis operation during reverse power flow conditions.

Solution: Aggregate should be added to the DER capacity determination and determination of capability of the voltage regulator handle the DER should be determined during supplemental review.

Commented [A55]: Concern: This FERC SGIP screen was not included in the current draft.

Example: Replacement of a dedicated transformer or service is required to accommodate a new DER. A path to supplemental review or study is needed to allow for scope development of necessary upgrades to proceed to facilities study.

Solution: This screen provides for a path to supplemental review or study necessary to determine scope of work and options to be passed to facilities study.

Commented [A56]: Concern: Other screens do not address the voltage impact of sudden generation or load changes on the electrical system. Use suggested new screen from US DOE sponsored BATIERS report.

Example: Generating facility uses export limiting and experiences inadvertent export such that the power quality and voltage of neighboring customers is affected.

Solution: This screen provides for a path to supplemental review, site modification, or study necessary to determine scope of work and options to be passed to a facilities study.

Commented [A57]: Concern: It is critical to ensure that a customer understands the tariff eligibility of a DER prior to moving to construction of that DER.

Example: Customer applies for DG tariff but the system size exceeds allowance under DG tariff. The electric utility should be able to provide that information to the interconnection customer as soon as possible.

Solution: Proposed language to allow the utility to notify the customer of a conflict between expected tariff and any know eligibility requirements.

the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant's request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(6).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(3).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

(5) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(2) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(3) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(4) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, and provides any reasonably requested data, an electric utility shall perform a supplemental review and notify the applicant of the results. The supplemental review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (2) of this rule to the proposed DER. The electric utility shall not require a system impact study if the DER passes the applied supplemental review screens.

Commented [A58]: **Concern:** Clarity to ensure that customers understand that all requirements including payment and providing any additional data are necessary to initiate supplemental review.

Example: Customer provides payment on 1/1/23 but requested data on 1/15/23, supplemental review timeline would start on 1/15/23.

Solution: Language as modified.

(5) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (6) and (7) of this rule. All of the following must be applied by the electric utility:

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in subrule (5)(a) of this rule. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section shall~~may~~ not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal ~~and emergency~~ ampacity.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(6) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(7) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(8) For subrules (6) and (7) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

(9) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or

Commented [A59]: **Concern:** Emergency ampacity is only used in abnormal configurations to maintain service until repairs can be completed.

Solution: remove language.

the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the non-export track or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted pursuant to R 460.936, the electric utility shall provide to the applicant an individual study agreement or an agreement for an alternative process pursuant to R 460.956.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), or (d), of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide to the applicant an individual study agreement or an agreement for an alternative process.

(4) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities study fee.

(5) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs.

(a) An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility determined the application to be complete and conforming.

(b) An application qualifies for study track pursuant to R 460.952.

(c) An interconnection application has a pre-application report, when required by R 460.936(2).

(d) An applicant has paid all required fees.

(e) An applicant has signed and returned an individual study agreement.

(f) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.956 Alternative process.

Rule 56. An electric utility may use a process to study interconnection applications that is different from the process described by R 460.954 and R 460.958 to R 460.962. If an electric utility elects to use an alternative process, this process must be described in the electric utility's interconnection procedures. Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to interconnection applications proceeding pursuant an individual study agreement.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.

(4) The scoping meeting may occur in-person or via telecommunications.

(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study, or an interconnection agreement and the basis for that decision, and 1 of the following must occur:

(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.

(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.

(c) If a system impact study is not required and a facilities study is not required, the interconnection application must proceed to R 460.964 for an interconnection agreement.

(d) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.960 System impact study agreement, scope, procedure, and review meeting.

Rule 60. (1) For all DERs being studied individually, all of the following apply:

(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.

(b) A system impact study agreement must include all of the following:

(i) An outline of the scope of the study.

(ii) The applicable fee including appropriate credit for any studies previously completed pursuant to the fast track or non-export track.

(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.

(iv) An estimated timeline for completion of the system impact study. In the event that acquisition of new or additional data, studies, or other information from an affected system or independent system operator such as the Midcontinent Independent System Operator, PJM or their successor organizations is indicated in order to perform a system impact study consistent with good utility practice, the time for completion of a system impact study is tolled until such information is received.

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(v) A list of the information that may~~must~~ be provided to the applicant in the system impact study report.

(vi) In no event shall the electric utility be required to provide information prior to full payment in advance or that the electric utility in good faith determines to be Critical Electric Infrastructure Information (CEII) or subject to National Electric Reliability Council Critical Infrastructure Protection (NERC CIP).

(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.

(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.

(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.

(f) The electric utility shall complete the system impact study and transmit a system impact study report to the applicant within 60 business days of the receipt of the signed system impact study agreement, payment of the system impact study fee, completion of system impact study review meeting (if requested), and receipt of any necessary technical data. If necessary, the electric utility shall transmit a facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data.

(g) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subrule (1)(f) of this rule. If the applicant cannot provide the data in a manner to allow the impact study to complete in 60 business days, the study shall be put on hold day for day until the data is received and then resume.

(h) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(i) Upon request by the applicant pursuant to subrule (1)(h) of this rule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25

Commented [A60]: Concern: Electric utility should not be accountable for the timelines of others.

Example: Updated transmission information is needed from the MISO model to determine expected system impedance at the point of interconnection to resolve potential issue with equipment short circuit interrupting capability rating.

Solution: Timeline must be tolled between notification of request for third party information and receipt of the information.

Commented [A61]: Concern: This is a rapidly evolving area of distribution systems.

Example: This list would provide an adversary a list of circuits that could be impacted based on if a specific technology has been compromised.

Solution: Electric utilities should be able to respond to new information as it becomes available to the industry.

Commented [A62]: Concern: If the applicant requests a study review meeting that may have a material effect on the direction of the facility study.

Solution: System impact study timeline should reflect customer input.

Commented [A63]: Concern: Interconnection customer need to be held to a timeline to respond to informational requests or utility studies can't be completed in a timely manner.

Example: A need for additional information is identified and communicated on day 5, the interconnection customer provides the data on day 59 of the study resulting in the need to restudy.

Solution: Proposed solution is to hold the study day for day until necessary information is provided.

business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(j) At the system impact study review meeting, the electric utility shall offer the applicant the option to withdraw the interconnection application, and 1 of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(k) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.

(l) The system impact study review meeting may occur in-person or via telecommunications.

(m) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.962 Facilities study agreement, scope, procedure; review meeting.

Rule 62. (1) For DERs being studied individually, all of the following apply:

(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. ~~If no system impact study was performed~~, ~~the~~ The electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.

(b) The facilities study agreement must include the following:

(i) An outline of the scope of the study.

(ii) The applicable fee including appropriate credit for any studies previously completed pursuant to the fast track or non-export track.

(iii) A timeline for completion of the facilities study.

(iv) A list of the information that will be provided to the applicant in the facilities study report.

(v) In no event shall the electric utility be required to provide information prior to full payment in advance or that the electric utility in good faith determines to be Critical Electric Infrastructure Information (CEII) or subject to National Electric Reliability Council Critical Infrastructure Protection (NERC CIP).

(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.

Commented [A64]: **Concern:** Clarity that in all cases a facilities study agreement should be provided within 10 days of proceeding to this rule.

Example/Solution: Suggested change provides consistency and clarity to when a facilities study agreement should be provided.

(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. ~~The electric utility shall provide cost estimates that are detailed and itemized.~~

(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.

(f) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee. If clarification or information is required from the applicant to complete the study, the study shall be put on hold day for day until the data is received and then resume.

(g) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:

(i) Request a facilities study review meeting with the electric utility.

(ii) Proceed to an interconnection agreement pursuant to R 460.964.

(iii) Withdraw the interconnection application.

If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.

(h) Upon request by the applicant pursuant to subrule (1)(g)(i) of this rule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.

(i) At the facilities study review meeting, the electric utility shall offer both of the following options:

(i) Proceed to an interconnection agreement pursuant to R 460.964.

(ii) Withdraw the interconnection application.

(j) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.

(k) The facilities study review meeting may be conducted in-person or via telecommunications.

(l) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

Commented [A65]: Concern: Interconnection customers need to be held to a timeline to respond to informational requests or utility studies can't be completed in a timely manner.

Example: A need for additional information is identified and communicated on day 5, the interconnection customer provides the data on day 59 of the study resulting in the need to restudy.

Solution: Proposed solution is to hold the study day for day until necessary information is provided.

Exhibit A

R 460.964 Interconnection agreement.

Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall ~~provide~~ transmit its ~~standard level 1, 2, and 3~~ interconnection agreement, which may include modifications to address any special operating conditions, to an applicant within 5~~3~~ business days of reaching this stage.

(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its ~~standard level 1, 2, and 3~~ interconnection agreement with modifications to address any special operating conditions, required construction activities, estimated construction milestone timing, and estimated cost to an applicant within 30~~5~~ business days of reaching this stage. The applicant and electric utility shall attempt to mutually agree on the timing of construction milestones consistent with the electric utility's other obligations, commercial reasonableness, and good utility practice.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the ~~standard level 1, 2, and 3~~ interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the ~~standard level 1, 2, and 3~~ interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and may grant an extension of 15 business days. If the electric utility did not receive the signed ~~standard level 1, 2, and 3~~ interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subrule 3(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, ~~the formal mediation pursuant to R 460.906,~~ or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the ~~standard level 1, 2, and 3~~ interconnection agreement within ~~1~~30 business days of the applicant returning the signed ~~standard level 1, 2, and 3~~ interconnection agreement and the interconnection application shall proceed to R 460.966.

(5) For level 4 or 5 projects, the electric utility shall provide its ~~level 4 and 5~~ interconnection agreement, which may include modifications to address any special operating conditions, within 30~~10~~ business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the ~~level 4 and 5~~ interconnection agreement must contain either estimated timelines for completion of activities and estimates of construction costs or a timetable when these requirements can be determined. The interconnection agreement must include ~~a~~ payment in advance for all estimated costs of interconnection facilities and distribution upgrades~~schedule that corresponds to the milestones established~~ and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

Commented [A66]: Concern: While most agreements are electronic, some customers still prefer hard copies. To achieve timelines electric utility should be measured on distributing the agreement not the customer receiving it.

Example: customer request agreement be mailed to home for review and signature.

Solution: replace provide with transmit to reflect the agreement being sent electronically or mailed.

Commented [A67]: Concern: Interconnection agreements should include all the same provisions a reasonable utility would make for normal commercial activity.

Solution: modified language to reflect cost and timing are estimates, extend the timeline for reaching a mutually agreeable schedule, and added clarification to ensure that interconnection agreements are consistent with other agreements the utility would make in the course of business.

Commented [A68]: Concern: Clarification of advanced payment

Example/Solution: modified language to make advanced payment clear.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the ~~level 4 and 5~~ interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and may grant an extension of 15 business days. If the electric utility does not receive the signed ~~level 4 and 5~~ interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subrule (6)(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, ~~formal mediation pursuant to R 460.906,~~ or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility's standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement and the interconnection application shall proceed to R 460.966.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. An applicant shall pay, in advance, or through timely payment in advance of milestones acceptable to the electric utility, the estimated cost of the interconnection facilities and distribution upgrades based upon the electric utility's standard construction, procurement, installation, design, and cost practices ~~The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of~~ If the cost for interconnection facilities and distribution upgrades exceeds the estimate ~~without an itemized summary and~~ by 125% the electric utility shall explain the~~nation of~~ cost increases being provided to the applicant. ~~If the costs are expected to exceed 125% of the estimate, the electric utility shall provide further explanation to the applicant prior to the costs being incurred. If the applicant does not consent in writing to pay the additional costs within 20 business days of receiving further explanation from the electric utility, the electric utility shall initiate informal mediation pursuant to R 460.904 no later than 5 business days after the conclusion of the 20 business day applicant consent period.~~ After payment of all actual costs up to 125% of the estimated costs, t~~T~~he applicant may dispute the amount by which the estimated ~~expected~~ costs exceed 125% of the estimated costs pursuant to either informal mediation pursuant to R 460.904, ~~formal mediation~~

~~pursuant to R 460.906,~~ or the complaint process pursuant to R 792.10439 to R 792.10446. ~~If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute.~~

~~(9) A party's obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:~~

~~(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.~~

~~(b) Propose the earliest alternate date when it can attain this and future milestones.~~

~~(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.~~

~~(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:~~

~~(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.~~

~~(b) The milestone under question has been previously delayed. (c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.~~

~~(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.~~

~~(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades.~~

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice only for computational errors and amounts that exceed 125% of the estimated costs pursuant to either informal mediation pursuant to R 460.904, ~~formal mediation pursuant to R 460.906,~~ or the complaint process pursuant to R 792.10439 to R 792.10446. ~~If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute.~~ Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER and the electric utility may transfer its resources to other electric utility work in its management discretion.

(b) If the applicant's previous aggregate payments exceed its costs under the interconnection agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations~~, provided that these modifications do not alter the rights or obligations of the interconnection customer~~. Unless

Commented [A69]: **Concern:** Dispute of costs to be paid should relieve the electric utility of the duty to continue progress on the project.

Example: While pursuing facilities construction a portion of the project is forced to reroute after permits where denied. This results in increased costs that the interconnection customer wishes to consider/dispute. The utility may divert resources to other projects pending resolution of the dispute.

Solution: Language as modified.

the electric utility has the consent of the applicant or interconnection customer in writing, an electric utility shall not modify a signed interconnection agreement without commission approval.

(15) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. Any required construction, coordination or shutdowns as specified in the interconnection agreement shall also be completed. The electric utility's interconnection procedures must describe the technical requirements of common items, but site-specific requirements may be included in the interconnection agreement including, but not limited to, initial and ongoing obligations for data exchange, cybersecurity, telemetry, operational control and protection configuration.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the ~~standard level 1, 2, and 3~~ interconnection agreement ~~or level 4 and 5 interconnection agreement~~.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days. If the electric utility finds the applicant's inspection, test reports, or configuration documents to be incomplete, insufficient, or unsatisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant shall have at least 20 business days or a mutually agreed to timeframe with the utility, to implement corrections to those documents. The applicant, after taking corrective action, shall request the electric utility to reconsider its inspection, test reports, or configuration documents.

(4) Upon the resolution of subrule (3), If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within the following:

(a) Ten business days of receiving the notification from the applicant pursuant to completion of subrule (2 &~~2~~3) of this rule for level 1 applications.

(b) Twenty business days of receiving the notification from the applicant pursuant to completion of subrule (2 &~~2~~3) of this rule for level 2 and level 3 applications.

Commented [A70]: **Concern:** Clarification that inspection, testing and commissioning occur under normal operating conditions including the full completion of any necessary facility work and required shutdowns.

Example: Customer requested testing prior to the completion of an overhead reconductoring project. As this reconductoring might impact the testing, the utility should be able to ensure any necessary testing occurs under conditions consistent with future operating conditions. Second example: customer has a CT enclosure that requires a shutdown to pull cables into the enclosure for their testing work to begin.

Solution: Addition of language to clarify need to test after all other work is complete.

Commented [A71]: **Concern:** Provide allowance for more complex interconnections, or where the applicant has internal scheduling constraints such as a production line shutdown or multi step construction project.

Example: PCS system configuration that requires shipping a component back to the vendor to reset.

Solution: provide for a mutually agreeable arrangement as an alternative fixed timeline.

Commented [A72]: **Concern:** Clarification that timelines under section (4) must follow and are not included in section (3)

Example: If in review, the applicant is required to fix a deficiency, the problem must be resolved prior to a site visit regardless if the utility has indicated that it will perform a witness test earlier. Sufficient time must be given to schedule this witness test.

Solution: Section 4 is dependent on the resolution of section 3.

Commented [A73]: **Concern:** Clarity around identifying when timelines begin.

Example/Solution: If an incomplete test record is provided and the utility elects to witness follow on testing the 10 days starts once the testing gap has been resolved.

(c) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to completion of subrule (2 & 3) of this rule for level 4 and 5 applications.

(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests.

(a) If the electric utility waives this right, it shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.

(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.

(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.

(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.

(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.

(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report.

(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.

(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response

within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.
(11) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.968 Authorization required prior to parallel operation.
Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:
(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.
(b) The applicant executed the parallel operating agreement required by the electric utility and complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.
(c) The applicant complied with all applicable local, state, and federal requirements.
(d) The electric utility received full payments for all outstanding bills.
(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.
(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.
(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.
(5) should the interconnection customer at any time fail to continue to meet these conditions or meet conditions set forth in R 460.978 the utility shall disconnect the customer until such time as the conditions are met to the utility's satisfaction
(6) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

Commented [A74]: Concern: clarification that the parallel operating agreement must be executed and complied with.

Example/Solution: language modified to reflect execution of agreement.

Commented [A75]: Concern: Adding clarity that authorization for parallel operation does not prevent the utility from disconnecting a DER if it is later discovered to not be meeting the conditions of the agreement.

Example: A project is discovered to have fallen out of technical compliance after reconfiguring their system operating practices.

Solution: language to ensure the utility right to disconnect and perform all necessary testing to ensure future compliance with parallel operating agreement and safety and reliability of the electrical grid.

R 460.970 Cost allocation of interconnection facilities, distribution upgrades, and associated operation and maintenance costs.

Rule 70. Costs for interconnection facilities, distribution upgrades, and associated operation and maintenance costs must be classified into 1 of the following categories:

(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs or not. These costs must be assigned to the cost-causing applicant.

(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs, including any associated operation and maintenance costs, that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs, including any associated operation and maintenance costs, that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

R 460.974 Interconnection metering and communications.

Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.

(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.

Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.

(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.

Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:

(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).
(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).
(c) Termination of interconnection by mutual agreement.
(d) Distribution system emergency, but only for the time necessary to resolve the emergency.
(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.
(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.
(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.
(h) Other material noncompliance with the interconnection agreement.
(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.

(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

(3) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.980 Capacity of the DER.

Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the ~~new ongoing operating~~aggregate nameplate capacity of the DER. The maximum capacity of a DER ~~is the aggregate nameplate capacity or~~ may be limited as described in the electric utility's interconnection procedures, subject to subsection (4)(g).

(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures, subject to subsection (4)(g).

(3) The electric utility's interconnection procedures must include acceptable methods for power limited export DER ~~–~~so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported, subject to subsection (4)(g). The utility may require back up methods or redundant schemes to mitigate any failure of these methods.

(4) An electric utility ~~shall~~may allow interconnection of limited-export or non-exporting DERs according to this subrule subject to the electric utility's rights under subsection

Commented [A76]: **Concern:** needs clarification to ensure that a capacity change is processed consistently with how a new application would be processed.

Solution: Project is reviewed at nameplate capacity and limited export will be considered, but must maintain safety, reliability and compliance with tariffs and programs.

Commented [A77]: **Concern:** The level of protection and operating expectations of a DER for component failure should be consistent with the risk of a mis-operation.

Example: a larger generator may be required to provide additional relaying to isolate the generator in the event of a breaker failure.

Solution: Make it explicit that utility grade protection and redundance practices are applicable to the interconnection customers as well.

(4)(g). If a DER uses any configuration or operating mode in this subrule to limit the export of electrical power across the point of common coupling, then the ~~generating~~ export capacity shall be only the amount capable of being exported not including any inadvertent export. To prevent impacts on system safety and reliability, any inadvertent export from a DER must comply with the limits in subdivisions (e) or (f) of this subrule. The ~~generating~~ export capacity specified by the applicant in the application will subsequently be included as a limitation in the interconnection agreement. Other means not listed in this subrule may be utilized to limit export if mutually agreed upon by the electric utility and applicant.

(a) To ensure power is never exported across the point of common coupling, a utility grade reverse power protective function may be provided. The default setting for this protective function shall ~~be 0.1%~~not exceed export of the service transformer's rating when including the total metering accuracy, with a maximum 2.0 second time delay~~.~~ or as determined by study.

(b)To ensure at least a minimum amount of power is imported across the point of common coupling at all times and, therefore, that power is not exported, an under-power protective function may be provided. The default setting for this protective function shall be 5% import of the DER's total nameplate rating, with a maximum 2.0 second time delay or as determined by study.

(c)This option requires the nameplate rating of the DER, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the distribution system. This option requires the DER capacity to be no greater than ~~50~~30% of the applicant's verifiable minimum host load over the past 12 months and shall include provisions to automatically curtail the exported power in any case that this minimum load is reduced further.

(d) A reduced output rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the nameplate rating.

(e) DERs may utilize, a nationally recognized testing laboratory certified power control system and inverter system that results in the DER disconnecting from the distribution system, ceasing to energize the distribution system or halting energy production within 2 seconds (or shorter as determined by study) if the period of continuous inadvertent export exceeds ~~30~~ 2 seconds. Failure of the control or inverter system for more than ~~30~~ 2 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER immediately entering an operational mode where ~~no energy is exported across the point of common coupling to the distribution system~~the DER disconnects from the utility system and cannot return to service until the loss of control or measurement signal is or control power is corrected and authorization is received from the utility to reconnect. The owner of a DER utilizing a certified power control system and inverter system described in this section shall obtain insurance in the amount of $10 million with respect to the DER, shall name the electric utility to which it is interconnected as an additional named insured, shall indemnify the electric utility to which it is interconnected for any and all damage and injury to electric utility personnel and property, and shall indemnify the electric utility to which it is interconnected for any and all third party claims, losses, damages, costs, charges,

Commented [A78]: **Concern:** modified language to ensure utility grade equipment, compliance with non-export function, account for metering capability, and provide allowance for maximum delay to be reduced based on study results without requiring system upgrades necessary to support maximum delay.

Example: the protective relay setting for a reverse power relay should default to zero export, and if a reaction time below 2 seconds is required for protective coordination, that delay should be provided by the study.

Solution: language as modified in (4a) and (4b)

Commented [A79]: **Concern:** Minimum verifiable load is a dynamic value and should adjust as the customer removes load or increases energy efficiency.

Solution: Language as modified

expenses, liens, settlements or judgments, including interest thereon, arising directly or indirectly out of operation of the DER.

(f) DERs may be designed with other control systems or protective functions, or both, to limit export and inadvertent export to levels mutually agreed upon by the applicant and the electric utility. The limits may be based on technical limitations of the applicant's equipment or the distribution system's equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the applicant shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

~~(f)~~(g)Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

Commented [A80]: Concern: UL 1741 PCS limitations only apply to the device which is certified. Any inadvertent export capability must also be reviewed against system conditions and grid capabilities. Failure to follow agreed export limits should result in cessation of operation and disconnection until control issues are resolved.

Example: A large DER offsetting a large load, experiences a loss of load resulting in the DER reaching its UL limit of 110% (132V) at the point of interconnection, utility distribution equipment which was compensating for low voltage prior to the inadvertent export event was set for 5% raise taking the distribution system to 115% or 138V, which would not be allowed to exist for 30 seconds by UL 1741 or any other industry standard.

Solution: Adjusted duration to 2 seconds to be consistent with industry standards for loss of export control, provide carveout for faster operation to limit potential need for upgrades, and add clarification on liability for failure to control export to as agreed to in agreements.

R 460.982 Modification of the interconnection application.

Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform an evaluation to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business days.

(2) The electric utility shall not be required to accept or implement a modification to the electric utility's distribution system or generation assets that is proposed by an applicant or affected system operator.

(3) The applicant may request a 1-hour consultation to discuss the results of the material modification review.

(4) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.

(5) For a proposed modification which the electric utility has determined is a material modification and that further study is required, the applicant shall select 1 of the following options:

(a) Withdraw the modification.

(b) Withdraw the application.

(c) Propose a different modification to the interconnection application for electric utility review pursuant to subrule (1) of this rule to determine whether the modification is material.

(d) If the electric utility offers an expedited study of the application with the proposed material modification, the applicant may request the expedited study. If the electric utility offers an expedited study, the process of performing an expedited study must be described in the electric utility's interconnection procedures.

(e) Initiate informal mediation pursuant to R 460.904

(f) Initial formal mediation pursuant to R460.906

(g) File a complaint pursuant to R 792.10439 to R 792.10446.

(6) The applicant shall notify the electric utility of its selection pursuant to subrule (5) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.

(7) For a proposed modification which the electric utility has determined is a material modification, but which does not require further study, the electric utility shall continue processing the interconnection application according to these rules.

(8) Any modification to the interconnection application that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.

(9) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.

(10) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.

Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant may not begin any material modification to the DER until an interconnection agreement incorporating the material modification is fully executed. Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.986 Insurance.
Rule 86. (1) An applicant interconnecting a level 1 or 2 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.
(2) An electric utility shall not require an applicant interconnecting a level 1 or 2 project to name the electric utility as an additional insured party.
(3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.
(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.
(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $3,000,000.
(6) For level 3, 4, and 5 projects, the electric utility may describe in its interconnection procedures required terms and conditions which must be specified in the general liability insurance.

R 460.988 Easements and rights-of-way.
Rule 88. If an electric utility line extension is required to accommodate an interconnection, the applicant~~electric utility~~ is responsible for providing and obtaining easements or rights-of-way. The applicant is responsible for the cost of providing and obtaining easements or rights-of-way.

Commented [A81]: **Concern:** This is not consistent with current tariff where customers provide easements.

Solution: Applicants should obtain easements according to specifications provided by the utility.

R 460.990 Interconnection penalties.
Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Business day exclusions.
Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to a day in which electric service is interrupted for 10% or more of an electric utility's customers pursuant to R 460.901a(k). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.

Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.

Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.

(2) Within calendar 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 calendar days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.

(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.

(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.

(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.

(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.

(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.

(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.

(8) An applicant shall notify the electric utility of plans for any material modification to the project. An applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule or R 460.1026. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application, including any necessary system impact study or facilities study. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

(9) Nothing in these rules shall be construed to foreclose an electric utility's right to test, study, examine, and if appropriate in the judgment of the electric utility not connect or disconnect a DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public. An electric utility shall not be prevented from testing, studying, or examining a proposed or interconnected DER that threatens the reliability of electric service or the safety of customers, utility employees, or the general public and any electric utility action pursuant to this right tolls any applicable deadlines under these rules until the matter is resolved.

R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on

the legacy net metering program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.

(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer’s account to permit the legacy net metering program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.

(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.

(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.

(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

R 460.1006 Distributed generation program application and fees.

Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for

interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility may complete its review of the distributed generation program application concurrently, before, or after processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.

(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:

(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer's account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.

(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(5) If a customer's distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.

(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility's distributed generation program tariff sheet or in the alternative electric supplier's distributed generation program plan.

(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer's interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.

Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173 or a voluntarily expanded program above the requirements defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.

(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.
(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.
(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.
Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.
Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:
(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.
(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.
(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.
(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:
(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer's power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer's power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility as described by R 460.1026.

R 460.1022 Renewable energy credits.

Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.

(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.

(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.

Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.

Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	))))))	Case No. U-20890

PROOF OF SERVICE

ESTELLA R. BRANSON states that on June 27, 2022, she served a copy of the DTE Electric Company's Comments in the above captioned matter, via electronic mail, upon the person listed on the attached service list.

ESTELLA R. BRANSON

MPSC Case No. U-20890
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No.U-20890

Introduction

Although the Michigan Energy Innovation Business Council ("Michigan EIBC") does not agree with the arguments made by Consumers Energy Company and DTE Electric Company in a Joint Petition for Rehearing ("Joint Petition") filed in this Docket on April 14, 2022, Michigan EIBC appreciates the opportunity to respond to the issues raised in the Joint Petition and to comment on the revised version of the MIXDG rules as proposed by the Commission in its March 17, 2022 Order ("final MIXDG rules"). Overall, Michigan EIBC is broadly supportive of the revised version of the MIXDG rules proposed by the Commission and believes that these standards will help enable the safe, but timely, interconnection of distributed energy resources ("DERs") in Michigan. Given that these rules have not been updated in more than a decade and given the changes that the electric grid has experienced over that time, it is critical that the Commission is able to provide improved guidance, timelines, and standards to meet the needs of the modern grid.

Michigan EIBC has been deeply involved in the Commission's process over the last four years to update the state's interconnection standards. In addition to participating throughout the workgroup process and submitting comments as appropriate, Michigan EIBC submitted comments and a redline of the draft MIXDG rules on November 1, 2021. Among the issues raised by Michigan EIBC in those comments/redline and consistently throughout the workgroup process were issues highlighted in the Joint Petition including those related to limited-export controls and standard fees. Responses to the concerns raised, as well as other comments on the proposed revised MIXDG rules, are outlined below.

Limited-Export Controls

In general, as stated in previous comments to the Commission, Michigan EIBC strongly believes that the MIXDG rules should include specific standards and definitions to allow for power-limited export DERs. The use of energy storage is growing significantly in Michigan among residential and commercial customers, and we anticipate increasing interest in distribution-connected storage as well. It is important that the interconnection standards spell out how storage will be treated and evaluated during the interconnection screening and study process, as is done in the final MIXDG rules. Furthermore, Michigan EIBC encourages the Commission to bear in mind that limitations on energy exports from DERs will be influenced by implementation of the Federal Energy Regulatory Commission's ("FERC") Order No. 2222. This rule will enable DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations, opening U.S. organized wholesale markets to new sources of energy and grid services. As FERC itself explains, the rule "will help provide a variety of benefits including lower costs for consumers through enhanced competition, more grid flexibility and resilience, and more innovation within the electric power industry."[1] Clearly FERC Order No. 2222 envisions energy export from DERs.

It is important to note that in the absence of clear Commission rules, as is currently the case, limited-export DERs are not treated consistently across the state. Michigan EIBC members work with customers who have encountered significant roadblocks for behind-the-meter solar plus storage systems with limited export. Specifically, in some cases, customer interconnection requests have been denied because the total capacity of a solar plus storage system is greater than 100 percent of the customers' annual electricity consumption despite the export (as limited by the inverter or power control system) of the solar plus storage system being far less than that amount. We expect this will also be a challenge for front-of-the-meter distribution connected storage. It is important to recognize that export from DC coupled solar plus storage systems is

[1] Federal Energy Regulatory Commission. "FERC Order No. 2222: Fact Sheet." September 17, 2020. Available at: https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

limited by the inverter (and therefore, the total potential output is not the sum of the capacity of the solar system and the storage system). Similarly, in AC coupled systems, energy storage systems will have their own inverters which can limit export.

Throughout the process to develop the final MIXDG rules, Michigan EIBC recommended that the Commission include specific limited-export standards for the utilities to follow as detailed in the 2019 Model Interconnection Rules from the Interstate Renewable Energy Council ("IREC"). These model rules follow guidance provided by FERC Order 845, which allows an interconnection customer to request service at a lower level than the nameplate generating facility capacity with the proper control technologies in place.

Consumers Energy and DTE Electric claim in their Joint Petition that "proposed Rules R 460.920 and R 460.980 appear designed to foreclose these electric utility legal rights and threaten the safety and reliability of the electric system in Michigan . . ."[2] The utilities appear to be concerned specifically about R 460.980, subsection 4(e), which reads:

> (e) DERs may utilize, a Nationally Recognized Testing Laboratory Certified Power Control System and inverter system that results in the DER disconnecting from the distribution system, ceasing to energize the distribution system or halting energy production within 2 seconds if the period of continuous inadvertent export exceeds 30 seconds. Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER entering an operational mode where no energy is exported across the point of common coupling to the distribution system.[3]

If a power control system does experience a short period of inadvertent export, the utilities argue in their Joint Petition that "[the] proposed rules effectively allow 32 seconds of dangerous operation until the project needs to come back into compliance. This short amount of time can cause a transformer to fail catastrophically (potentially including a fire) and seriously impact

[2] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. pp. 7-8.
[3] Michigan Public Service Commission Order. Case No. U-20890. March 17, 2022. p. 44.

power quality to adjacent customers (potentially including appliance failures)."[4] For a number of reasons, as outlined below, this argument is false and should be rejected.

First, in general, the maximum amount of inadvertent export from a limited-export system for a short period of time is not sufficient to cause damage to conductors or thermal impacts. According to the Storage Interconnection Committee of the Building a Technically Reliable Interconnection Evolution for Storage ("BATRIES") Project Team, which conducted testing of power control systems, most are able to respond very quickly (i.e., within 10 seconds).[5] For example, of the 59 power control system devices on the California Energy Commission's approved solar equipment list, as of October 2021, all but one have an inadvertent export response time of 10 seconds or less.[6] Simply from a thermodynamics perspective, these potential short periods of inadvertent export cannot cause catastrophic thermal failures as suggested by the utilities. As stated by the BATRIES Project Team, "thermal impacts were not modeled for inadvertent export because both their level (110% max) and duration (typically 2-10 seconds) were below any known thresholds for concern."[7] This is also true because utility infrastructure is designed to safely be operated in overload conditions, especially for these very short time periods, to ensure grid flexibility in meeting unexpected needs. For example, ISO-NE Capacity Rating Procedure requires infrastructure to be designed and rated for overloading operations for 15-minute emergencies and durations up to 12 hours.[8]

Second, the standards proposed by the Commission for limited-export in the final MIXDG rules are aligned with national certifications and codes from UL, the Institute of Electrical and Electronics Engineers ("IEEE") and the National Electrical Code ("NEC"). Currently, the UL 1741 Certification Requirement Decision ("CRD") for power control systems requires a response

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[4] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. p. 8.
[5] Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Project Team. Storage Interconnection Team. "Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage." March 2022. Available at: https://energystorageinterconnection.org/resources/batries-toolkit/.
[6] California Energy Commission. "*Inverter and Energy Storage System PCS List.*" Oct. 21, 2021. Available at: https://solarequipment.energy.ca.gov/Home/DownloadtoExcel?filename=PowerControlSystem.
[7] Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Project Team. Storage Interconnection Team. "Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage." March 2022. Available at: https://energystorageinterconnection.org/resources/batries-toolkit/. pp. 82-83.
[8] ISO-NE. "Capacity Rating Procedures by the System Design Task Force." Corrected October 2004. Available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp07/capacity_rating_procedures.pdf.

time of under 30 seconds to instances of inadvertent export. Similarly, the NEC, which is a standard for safety related to fires, includes a requirement that any inadvertent export is limited to less than 30 seconds. A similar situation can be found in the IEEE 1547-2018 standard, which requires in section 4.6.1 that a DER "shall be capable of disabling the permit service setting and shall cease to energize the Area EPS and trip in no more than 2 s."[9] Section 4.6.2 goes on to indicate that "The DER shall limit its active power output to not greater than the active power limit set point in no more than 30 s or in the time it takes for the primary energy source to reduce its active power output to achieve the requirements of the active power limit set point, whichever is greater."[10] In general, IEEE standards are developed by consensus and reflect the accepted best practice at the time of adoption. IEEE 1547-2018 was developed by a working group of more than 100 experts, and balloted by a pool of more than 300 voters, which was balanced across user communities, including electric utilities. An approval rate of at least 75% was required, with an answer provided to all comments. As such, it is clear that these standards reflect consensus, reasonable, best practices.

Third, the standards proposed by the Commission for limited-export in the final MIXDG rules are aligned with the Model Interconnection Procedures from IREC.[11] Moreover, Michigan EIBC is unaware of any state jurisdictions that have gone through a formal energy storage interconnection rulemaking process and have not adopted rules to enable limited-export allowances. While terminology may vary within the actual rules across different jurisdictions, Illinois recently adopted rules allowing for limited-export[12, 13] and similar rules are pending in New Mexico, Connecticut, Massachusetts, Vermont, and Puerto Rico. Furthermore, limited-export allowances and standards have been established within interconnection rules using a variety of approaches in New York, Maryland, Colorado, Arizona, Nevada, Minnesota,

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[9] IEEE Standards Association. "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces." 2018. Available at: https://web.nit.ac.ir/~shahabi.m/M.Sc%20and%20PhD%20materials/DGs%20and%20MicroGrids%20Course/Standards/IEEE%20Std%201547/IEEE%20Std%201547™-2018.pdf.

[10] *Ibid.*

[11] Interstate Renewable Energy Council. "Model Interconnection Procedures." 2019. Available at: https://irecusa.org/resources/irec-model-interconnection-procedures-2019/.

[12] Illinois Commerce Commission. Docket 20-0700. Final Order. May 25, 2022. Available at: https://www.icc.illinois.gov/docket/P2020-0700/documents/324414.

[13] Misbrener, K. "Illinois rule changes will simplify solar + storage interconnection." *Solar Power World*. Available at: https://www.solarpowerworldonline.com/2022/06/illinois-rule-changes-will-simplify-solar-storage-interconnection/.

California and Hawaii. In Hawaii, for example, limited-export standards have been in place since 2016. Despite the incredibly high penetration of DERs in Hawaii, Hawaiian Electric has not filed comments or discussed with stakeholders any record of thermal impacts or reported safety concerns related to inadvertent export from systems with limited-export controls.

Overall, it is clear both that multiple states have adopted or are adopting rules similar to what the Commission contemplates and to which Consumers Energy and DTE Electric object, and regardless of what rules a state adopts, the safety and technical standards still apply. For these reasons, Consumers Energy and DTE Electric's "safety arguments" should be seen for what they are — an attempt to dissuade the Commission from adopting meaningful updates to its interconnection rules that will advance customers' energy independence and resiliency.

Standard Fees

In general, as stated in previous comments to the Commission, Michigan EIBC believes that fees for the pre-application reports, simplified track (see comments below), non-export track, and fast track should be established uniformly by the Commission. It is well-established that interconnection applicants should pay the full costs of any required in-depth studies, but reasonable initial fee caps should also be established by the Commission. The final MIXDG rules establish reasonable fees for pre-application reports, non-export track, and fast track as well as initial fee caps for more in-depth studies. However, the utilities argue in their Joint Petition that "[there] is a problem with the fees that the MIXDG rules use for actions and studies required by the rules. . ."[14]

The initial fees established in the final MIXDG rules for the pre-application report ($300), non-export track ($100 + $1/kWac), and fast track initial review ($100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs) are aligned with those in the Model Interconnection Procedures established by IREC.[15] As such, similar standard fees have been

[14] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. p. 18.
[15] Interstate Renewable Energy Council. "Model Interconnection Procedures." 2019. Available at: https://irecusa.org/resources/irec-model-interconnection-procedures-2019/.

established by other states including, for example Illinois,[16] New Mexico,[17] Pennsylvania,[18] and Utah.[19] The reviews required by the utilities for the pre-application report, non-export track, and fast track initial review are relatively limited in scope. For example, in the final MIXDG rules, according to R 460.932, "[the] pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available." Similarly, for the initial fast track review, the utility is required only to review the DER using a limited number of relatively simple initial review screens (R 460.946). There is no clear reason why Michigan's utilities should have significantly higher costs than other Midwest utilities to conduct these initial reviews or, if they do currently have higher costs, why efficiencies could not be found to decrease costs.

The fees, as outlined in the final MIXDG rules, for the pre-application report, non-export track, and fast track initial review are reasonable and should serve as reasonable limits on what a utility may collect. However, as outlined below, according to R 460.926 (4), an electric utility "that expects to incur costs greater than the fees listed in subrule (2) or initial fee caps listed in subrule (3) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910."[20] A determination as to whether such a waiver is warranted would likely be made by the Commission under an expedited proceeding and without the level of stakeholder participation that occurs during a contested case proceeding. Given the language in R 460.926, it is unclear whether a utility would have to prove, via the provision of actual expenses, that their costs exceed those listed in the final MIXDG rules to obtain a waiver. As such, Michigan EIBC

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[16] Illinois Joint Committee on Administrative Rules. Title 83: Public Utilities, Chapter 1: Illinois Commerce Commission, Subchapter c: Electric Utilities, Part 466 Electric Interconnection of Distributed Generation Facilities. Available at: https://www.ilga.gov/commission/jcar/admincode/083/08300466sections.html.

[17] New Mexico Commission of Public Records. Title 17: Public Utilities and Utility Services, Chapter 9: Electric Services, Part 568: Interconnection of Generating Facilities with a Rated Capacity up to and Including 10 MW Connecting to a Utility System. Available at: https://www.srca.nm.gov/parts/title17/17.009.0568.html.

[18] Commonwealth of Pennsylvania. Pennsylvania Code. Title 52, Chapter 69. Available at: https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter69/s69.2104.html&d=reduce#:~:text=§%2069.2104.-,Interconnection%20application%20fees.,relating%20to%20interconnection%20standards)%3A.

[19] Utah Admin. Code 746-312-13. Available at: https://casetext.com/regulation/utah-administrative-code/public-service-commission/title-r746-administration/rule-r746-312-electrical-interconnection/section-r746-312-13-interconnection-fees-and-charges.

[20] Michigan Public Service Commission Order. Case No. U-20890. March 17, 2022.

does not believe that a utility should be allowed to petition for a waiver of the fees listed in R 460.926 subrule (2) for the pre-application report, non-export track, and fast track initial review without a clear showing with evidence (e.g., through a contested case process) that reasonable utility processes to undertake these reviews cost more than the established fees.

Material Modifications

In their Joint Petition, the utilities state that changes to the definition of "material modification" in the final MIXDG rules "presents the [utilities] with a virtually infinite number of illegal, unsafe, and unreliable configurations with no apparent recourse."[21] Specifically, the Joint Petition notes concerns with the addition of a statement in R 460.901b(n) that "[replacing] a component with another component that has near-identical characteristics does not constitute a material modification." Michigan EIBC strongly encourages the Commission to reject these arguments and retain the language in R 460.901b(n), including the description of the required review to determine that a modification is material, in the final MIXDG rules.

Throughout the development of the MIXDG rules, Michigan EIBC provided comments emphasizing the importance of ensuring that fair, thorough reviews are conducted to determine whether or not a modification is "material" in nature. It is critical, as is done in the final MIXDG rules, that the Commission spell out clearly in the rules what types of changes are material and what types of changes are not material. This is especially important for projects that go through the study track, given that the time between initial application and approved interconnection agreement can be quite long. As a result, equipment or parts included in an initial application may no longer be available. If that is the case, it is critical that an applicant be able to substitute a "near-identical" component from a different manufacturer, and that such an allowance be clearly indicated in the rules.

Separately, it is critical in the legacy net metering ("LNM") and distributed generation ("DG") section of the MIXDG rules that the addition of energy storage to an existing DG system does

[21] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. p. 13.

not result in an applicant being terminated from the LNM or DG program. The final rules state in R 460.1001 (7)(c) that:

> The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.[22]

It appears that the intention of the Commission is to avoid the situation where a rooftop solar customer in the LNM or DG program with multiple years still left on their agreement is removed from the program when that customer adds an on-site energy storage system. However, if the addition of an energy storage device to an existing LNM or DG program system is considered a material modification (as stated in the final MIXDG rules), it is likely that a utility would require a customer adding an energy storage device to file a new interconnection application, which could trigger removal from the LNM or DG program. However, given that these systems would be export-limited with an inverter or power supply controller, the addition of storage will not increase the generation capacity of the customer's electric generator. As such, based on a plain reading of section 183 of Public Act 342, it would be illegal to remove the customer against their will from the LNM or DG program prior to the end of the grandfathering period.[23] This will become more critical toward the end of 2022 as installations near the DG program caps for both DTE Electric and Consumers Energy. If the relevant DG cap has been reached, a customer who needs to reapply when adding a storage system may find the DG program closed and then may not only not be able to add their storage device, but also, may be unable to continue to use their existing solar panels. If the Commission retains the language in R 460.1001 (7)(c), it is critical that the Commission also clearly confirm that utility procedures must ensure that customers are not harmed.

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[22] Michigan Public Service Commission Order. Case No. U-20890. March 17, 2022. p. 49.
[23] Public Act 342 of 2016. Section 183. Available at: https://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm.

Simplified Track

In the final MIXDG rules as proposed, the Commission deleted the simplified track, which was a set of limited screens to evaluate level 1 or level 2 projects. Throughout the process to develop the MIXDG rules, Michigan EIBC advocated for and supported the addition of the simplified track. Although the screens in the simplified track were a subset of those included in the fast track, by selecting the screens most critical to evaluate small projects, the simplified track would enable a faster, more streamlined evaluation of the smallest on-site generators that are very unlikely to require additional study.

Michigan EIBC strongly recommends that the Commission retain the simplified track in the MIXDG rules. In addition to the ability to streamline projects, the simplified track also required that the fee for the simplified track plus any LNM or DG program application fee could not together exceed a total of $50. However, with the deletion of the simplified track (as is done in the final MIXDG rules), level 1 and 2 projects would instead go through fast track, which has a fee of $100 + $1/kWac. There is no language in the final MIXDG rules to ensure that a customer would not be charged both a LNM or DG program application fee of $50 plus a fast track fee of $100 + $1/kWac. A customer with a 50 kW level 2 project applying for interconnection under the DG program would have paid $50 in total under the previous version of the MIXDG rules. With the elimination of the simplified track, that same customer may have to pay a $50 application fee for the DG program plus a $150 fee for the fast track, for a total of $200. In addition to the ability to streamline and quickly review level 1 and 2 projects, the retention of the simplified track would provide clear, reasonable, and standard fees for customers. Moreover, increased fees for level 1 customers do nothing to help ensure that middle- and lower-income customers can access DERs. It is these customers who could often benefit most from the long-term savings provided by DERs.

Interconnection Penalties

Michigan EIBC observes that the interconnection penalties provided for in R 460.990 only apply to DERs greater than 100 kW. Smaller systems are more frequently associated with smaller customers, who are less likely to have the resources to protect their right to interconnect under the MIXDG rules. Allowing an electric utility to impede interconnection for smaller systems without consequences sends the wrong message to utilities and treats smaller customers as second-class customers. Michigan EIBC recommends that the Commission revise R 460.990 to remove 100 kW limitation on the availability of penalties as follows:

> R 460.990 Interconnection penalties.
>
> Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER ~~greater than 100 kW~~ to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

Recommended Clarifications

As the Commission considers further comments on the MIXDG rules, Michigan EIBC suggests certain clarifications to improve the rules and facilitate interconnection.

First, related to informal mediation under R 460.904, rule 4(3) provides that the parties to an interconnection dispute may request informal mediation by a Commission interconnection ombudsperson. The rule, however, does not specify any timeframe by when such informal mediation must occur. Because time is often important to the interconnection process and the MIXDG rules *require* other dispute resolution steps that may be needed before an interconnection dispute is resolved, Michigan EIBC suggests that the Commission require an initial meeting with the ombudsperson within 10 days of the request for informal mediation being submitted. The absence of such language may unnecessarily prolong the resolution of an interconnection dispute. Specifically, Michigan EIBC recommends that Rule 4(3) be revised as follows:

> (3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall **<u>commence within 10 days of submission of the written request and</u>** be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

Second, related to R 460.906 and the provisions governing formal mediation, rule 6(1) provides that if "the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:" This language implies that informal mediation is required, but R 460.904 clearly characterizes informal mediation as voluntary after the direct discussion and informal negotiation required under Rule 4(2). Because time is often important in interconnection, Michigan EIBC agrees with treating informal mediation as an optional step in the dispute resolution process. To remedy this inconsistency with R 460.904, Michigan EIBC recommends revising Rule 6(1) of R 406.906 to read as:

> (1) If the parties have been unable to resolve a dispute through **<u>either the required direct discussion or informal negotiation or</u>** the **voluntary** informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

Third, we recommend a revision related to R 460.910, which provides for waivers. As written, Rule 10 is ambiguous as to which party has the burden of demonstrating the necessity of a waiver, the duration of any waiver, and the circumstances under which a waiver may be granted. Michigan EIBC proposes deleting the existing Rule 10 and replacing it with the following:

> R 460.910 Waivers
>
> Rule 10. (1) The Commission may, on application of an electric utility, customer, alternative electric supplier, or interconnection customer, or on its own motion,

> grant a temporary or permanent waiver from 1 or more provisions of these rules in situations in which the Commission finds that:
> (a) the provision from which the waiver is granted is not statutorily mandated;
> (b) there is good cause for the waiver, and it is in the public interest; and
> (c) the provision from which the waiver is granted would, as applied in the presented situation, be unreasonable or unnecessarily burdensome.
> (2) The burden of proof in establishing a right to a waiver shall be on the party seeking the waiver.
> (3) An applicant for a waiver may request expeditious processing.

Fourth, related to interconnection applications under R 460.936, rule 36(7)(b) sets forth the electric utility's obligation to provide a written list of deficiencies in an interconnection application and how such deficiencies are to be addressed. Importantly, however, the rule does not prevent the utility from later adding to the list new, unrelated deficiencies. To prevent a utility from unnecessarily prolonging the interconnection process, the Commission should clarify the rule to confirm the utility's obligation to provide a *comprehensive* list of deficiencies within 10 days of submission of an interconnection application. Michigan EIBC proposes the following modification of Rule 36(7)(b):

> (b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. <u>**A utility may not identify additional deficiencies beyond those originally identified.**</u> If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

Michigan EIBC's final recommendation is related to the requirement in R 460.938 that an electric utility publish on its website a list of interconnection requests it has received. As written, the rule seems to suggest that in a month in which no changes have occurred, no update whatsoever is required to the list. In such situations, it would not be clear whether the lack of an update is due to the lack of any changes or the failure to update the list as required. To avoid any confusion, Michigan EIBC recommends that the rule require a utility to at least update the list to indicate that no changes have occurred since the prior month. Michigan EIBC suggests the following language to reflect this:

> (1) An electric utility shall maintain a publicly available interconnection list, which is available in a sortable spreadsheet format. The sortable spreadsheet must be provided to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly<u>**. If**</u> ~~unless~~ no changes to the spreadsheet have occurred in that month<u>**, a note to that effect must be clearly indicated on the spreadsheet**</u>. The date of the most recent update must be clearly indicated.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No.U-20890

Introduction

Although the Michigan Energy Innovation Business Council ("Michigan EIBC") does not agree with the arguments made by Consumers Energy Company and DTE Electric Company in a Joint Petition for Rehearing ("Joint Petition") filed in this Docket on April 14, 2022, Michigan EIBC appreciates the opportunity to respond to the issues raised in the Joint Petition and to comment on the revised version of the MIXDG rules as proposed by the Commission in its March 17, 2022 Order ("final MIXDG rules"). Overall, Michigan EIBC is broadly supportive of the revised version of the MIXDG rules proposed by the Commission and believes that these standards will help enable the safe, but timely, interconnection of distributed energy resources ("DERs") in Michigan. Given that these rules have not been updated in more than a decade and given the changes that the electric grid has experienced over that time, it is critical that the Commission is able to provide improved guidance, timelines, and standards to meet the needs of the modern grid.

Michigan EIBC has been deeply involved in the Commission's process over the last four years to update the state's interconnection standards. In addition to participating throughout the workgroup process and submitting comments as appropriate, Michigan EIBC submitted comments and a redline of the draft MIXDG rules on November 1, 2021. Among the issues raised by Michigan EIBC in those comments/redline and consistently throughout the workgroup process were issues highlighted in the Joint Petition including those related to limited-export controls and standard fees. Responses to the concerns raised, as well as other comments on the proposed revised MIXDG rules, are outlined below.

Limited-Export Controls

In general, as stated in previous comments to the Commission, Michigan EIBC strongly believes that the MIXDG rules should include specific standards and definitions to allow for power-limited export DERs. The use of energy storage is growing significantly in Michigan among residential and commercial customers, and we anticipate increasing interest in distribution-connected storage as well. It is important that the interconnection standards spell out how storage will be treated and evaluated during the interconnection screening and study process, as is done in the final MIXDG rules. Furthermore, Michigan EIBC encourages the Commission to bear in mind that limitations on energy exports from DERs will be influenced by implementation of the Federal Energy Regulatory Commission's ("FERC") Order No. 2222. This rule will enable DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations, opening U.S. organized wholesale markets to new sources of energy and grid services. As FERC itself explains, the rule "will help provide a variety of benefits including lower costs for consumers through enhanced competition, more grid flexibility and resilience, and more innovation within the electric power industry."[1] Clearly FERC Order No. 2222 envisions energy export from DERs.

It is important to note that in the absence of clear Commission rules, as is currently the case, limited-export DERs are not treated consistently across the state. Michigan EIBC members work with customers who have encountered significant roadblocks for behind-the-meter solar plus storage systems with limited export. Specifically, in some cases, customer interconnection requests have been denied because the total capacity of a solar plus storage system is greater than 100 percent of the customers' annual electricity consumption despite the export (as limited by the inverter or power control system) of the solar plus storage system being far less than that amount. We expect this will also be a challenge for front-of-the-meter distribution connected storage. It is important to recognize that export from DC coupled solar plus storage systems is

[1] Federal Energy Regulatory Commission. "FERC Order No. 2222: Fact Sheet." September 17, 2020. Available at: https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

limited by the inverter (and therefore, the total potential output is not the sum of the capacity of the solar system and the storage system). Similarly, in AC coupled systems, energy storage systems will have their own inverters which can limit export.

Throughout the process to develop the final MIXDG rules, Michigan EIBC recommended that the Commission include specific limited-export standards for the utilities to follow as detailed in the 2019 Model Interconnection Rules from the Interstate Renewable Energy Council ("IREC"). These model rules follow guidance provided by FERC Order 845, which allows an interconnection customer to request service at a lower level than the nameplate generating facility capacity with the proper control technologies in place.

Consumers Energy and DTE Electric claim in their Joint Petition that "proposed Rules R 460.920 and R 460.980 appear designed to foreclose these electric utility legal rights and threaten the safety and reliability of the electric system in Michigan . . ."[2] The utilities appear to be concerned specifically about R 460.980, subsection 4(e), which reads:

> (e) DERs may utilize, a Nationally Recognized Testing Laboratory Certified Power Control System and inverter system that results in the DER disconnecting from the distribution system, ceasing to energize the distribution system or halting energy production within 2 seconds if the period of continuous inadvertent export exceeds 30 seconds. Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER entering an operational mode where no energy is exported across the point of common coupling to the distribution system.[3]

If a power control system does experience a short period of inadvertent export, the utilities argue in their Joint Petition that "[the] proposed rules effectively allow 32 seconds of dangerous operation until the project needs to come back into compliance. This short amount of time can cause a transformer to fail catastrophically (potentially including a fire) and seriously impact

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power quality to adjacent customers (potentially including appliance failures)."[4] For a number of reasons, as outlined below, this argument is false and should be rejected.

First, in general, the maximum amount of inadvertent export from a limited-export system for a short period of time is not sufficient to cause damage to conductors or thermal impacts. According to the Storage Interconnection Committee of the Building a Technically Reliable Interconnection Evolution for Storage ("BATRIES") Project Team, which conducted testing of power control systems, most are able to respond very quickly (i.e., within 10 seconds).[5] For example, of the 59 power control system devices on the California Energy Commission's approved solar equipment list, as of October 2021, all but one have an inadvertent export response time of 10 seconds or less.[6] Simply from a thermodynamics perspective, these potential short periods of inadvertent export cannot cause catastrophic thermal failures as suggested by the utilities. As stated by the BATRIES Project Team, "thermal impacts were not modeled for inadvertent export because both their level (110% max) and duration (typically 2-10 seconds) were below any known thresholds for concern."[7] This is also true because utility infrastructure is designed to safely be operated in overload conditions, especially for these very short time periods, to ensure grid flexibility in meeting unexpected needs. For example, ISO-NE Capacity Rating Procedure requires infrastructure to be designed and rated for overloading operations for 15-minute emergencies and durations up to 12 hours.[8]

Second, the standards proposed by the Commission for limited-export in the final MIXDG rules are aligned with national certifications and codes from UL, the Institute of Electrical and Electronics Engineers ("IEEE") and the National Electrical Code ("NEC"). Currently, the UL 1741 Certification Requirement Decision ("CRD") for power control systems requires a response

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[6] California Energy Commission. "*Inverter and Energy Storage System PCS List.*" Oct. 21, 2021. Available at: https://solarequipment.energy.ca.gov/Home/DownloadtoExcel?filename=PowerControlSystem.
[7] Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Project Team. Storage Interconnection Team. "Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage." March 2022. Available at: https://energystorageinterconnection.org/resources/batries-toolkit/. pp. 82-83.
[8] ISO-NE. "Capacity Rating Procedures by the System Design Task Force." Corrected October 2004. Available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp07/capacity_rating_procedures.pdf.

time of under 30 seconds to instances of inadvertent export. Similarly, the NEC, which is a standard for safety related to fires, includes a requirement that any inadvertent export is limited to less than 30 seconds. A similar situation can be found in the IEEE 1547-2018 standard, which requires in section 4.6.1 that a DER "shall be capable of disabling the permit service setting and shall cease to energize the Area EPS and trip in no more than 2 s."[9] Section 4.6.2 goes on to indicate that "The DER shall limit its active power output to not greater than the active power limit set point in no more than 30 s or in the time it takes for the primary energy source to reduce its active power output to achieve the requirements of the active power limit set point, whichever is greater."[10] In general, IEEE standards are developed by consensus and reflect the accepted best practice at the time of adoption. IEEE 1547-2018 was developed by a working group of more than 100 experts, and balloted by a pool of more than 300 voters, which was balanced across user communities, including electric utilities. An approval rate of at least 75% was required, with an answer provided to all comments. As such, it is clear that these standards reflect consensus, reasonable, best practices.

Third, the standards proposed by the Commission for limited-export in the final MIXDG rules are aligned with the Model Interconnection Procedures from IREC.[11] Moreover, Michigan EIBC is unaware of any state jurisdictions that have gone through a formal energy storage interconnection rulemaking process and have not adopted rules to enable limited-export allowances. While terminology may vary within the actual rules across different jurisdictions, Illinois recently adopted rules allowing for limited-export[12, 13] and similar rules are pending in New Mexico, Connecticut, Massachusetts, Vermont, and Puerto Rico. Furthermore, limited-export allowances and standards have been established within interconnection rules using a variety of approaches in New York, Maryland, Colorado, Arizona, Nevada, Minnesota,

[9] IEEE Standards Association. "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces." 2018. Available at: https://web.nit.ac.ir/~shahabi.m/M.Sc%20and%20PhD%20materials/DGs%20and%20MicroGrids%20Course/Standards/IEEE%20Std%201547/IEEE%20Std%201547™-2018.pdf.

[10] *Ibid.*

[11] Interstate Renewable Energy Council. "Model Interconnection Procedures." 2019. Available at: https://irecusa.org/resources/irec-model-interconnection-procedures-2019/.

[12] Illinois Commerce Commission. Docket 20-0700. Final Order. May 25, 2022. Available at: https://www.icc.illinois.gov/docket/P2020-0700/documents/324414.

[13] Misbrener, K. "Illinois rule changes will simplify solar + storage interconnection." *Solar Power World*. Available at: https://www.solarpowerworldonline.com/2022/06/illinois-rule-changes-will-simplify-solar-storage-interconnection/.

California and Hawaii. In Hawaii, for example, limited-export standards have been in place since 2016. Despite the incredibly high penetration of DERs in Hawaii, Hawaiian Electric has not filed comments or discussed with stakeholders any record of thermal impacts or reported safety concerns related to inadvertent export from systems with limited-export controls.

Overall, it is clear both that multiple states have adopted or are adopting rules similar to what the Commission contemplates and to which Consumers Energy and DTE Electric object, and regardless of what rules a state adopts, the safety and technical standards still apply. For these reasons, Consumers Energy and DTE Electric's "safety arguments" should be seen for what they are — an attempt to dissuade the Commission from adopting meaningful updates to its interconnection rules that will advance customers' energy independence and resiliency.

Standard Fees

In general, as stated in previous comments to the Commission, Michigan EIBC believes that fees for the pre-application reports, simplified track (see comments below), non-export track, and fast track should be established uniformly by the Commission. It is well-established that interconnection applicants should pay the full costs of any required in-depth studies, but reasonable initial fee caps should also be established by the Commission. The final MIXDG rules establish reasonable fees for pre-application reports, non-export track, and fast track as well as initial fee caps for more in-depth studies. However, the utilities argue in their Joint Petition that "[there] is a problem with the fees that the MIXDG rules use for actions and studies required by the rules. . ."[14]

The initial fees established in the final MIXDG rules for the pre-application report ($300), non-export track ($100 + $1/kWac), and fast track initial review ($100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs) are aligned with those in the Model Interconnection Procedures established by IREC.[15] As such, similar standard fees have been

[14] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. p. 18.
[15] Interstate Renewable Energy Council. "Model Interconnection Procedures." 2019. Available at: https://irecusa.org/resources/irec-model-interconnection-procedures-2019/.

established by other states including, for example Illinois,[16] New Mexico,[17] Pennsylvania,[18] and Utah.[19] The reviews required by the utilities for the pre-application report, non-export track, and fast track initial review are relatively limited in scope. For example, in the final MIXDG rules, according to R 460.932, "[the] pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available." Similarly, for the initial fast track review, the utility is required only to review the DER using a limited number of relatively simple initial review screens (R 460.946). There is no clear reason why Michigan's utilities should have significantly higher costs than other Midwest utilities to conduct these initial reviews or, if they do currently have higher costs, why efficiencies could not be found to decrease costs.

The fees, as outlined in the final MIXDG rules, for the pre-application report, non-export track, and fast track initial review are reasonable and should serve as reasonable limits on what a utility may collect. However, as outlined below, according to R 460.926 (4), an electric utility "that expects to incur costs greater than the fees listed in subrule (2) or initial fee caps listed in subrule (3) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910."[20] A determination as to whether such a waiver is warranted would likely be made by the Commission under an expedited proceeding and without the level of stakeholder participation that occurs during a contested case proceeding. Given the language in R 460.926, it is unclear whether a utility would have to prove, via the provision of actual expenses, that their costs exceed those listed in the final MIXDG rules to obtain a waiver. As such, Michigan EIBC

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[16] Illinois Joint Committee on Administrative Rules. Title 83: Public Utilities, Chapter 1: Illinois Commerce Commission, Subchapter c: Electric Utilities, Part 466 Electric Interconnection of Distributed Generation Facilities. Available at: https://www.ilga.gov/commission/jcar/admincode/083/08300466sections.html.
[17] New Mexico Commission of Public Records. Title 17: Public Utilities and Utility Services, Chapter 9: Electric Services, Part 568: Interconnection of Generating Facilities with a Rated Capacity up to and Including 10 MW Connecting to a Utility System. Available at: https://www.srca.nm.gov/parts/title17/17.009.0568.html.
[18] Commonwealth of Pennsylvania. Pennsylvania Code. Title 52, Chapter 69. Available at: https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/052/chapter69/s69.2104.html&d=reduce#:~:text=§%2069.2104.-,Interconnection%20application%20fees.,relating%20to%20interconnection%20standards)%3A.
[19] Utah Admin. Code 746-312-13. Available at: https://casetext.com/regulation/utah-administrative-code/public-service-commission/title-r746-administration/rule-r746-312-electrical-interconnection/section-r746-312-13-interconnection-fees-and-charges.
[20] Michigan Public Service Commission Order. Case No. U-20890. March 17, 2022.

does not believe that a utility should be allowed to petition for a waiver of the fees listed in R 460.926 subrule (2) for the pre-application report, non-export track, and fast track initial review without a clear showing with evidence (e.g., through a contested case process) that reasonable utility processes to undertake these reviews cost more than the established fees.

Material Modifications

In their Joint Petition, the utilities state that changes to the definition of "material modification" in the final MIXDG rules "presents the [utilities] with a virtually infinite number of illegal, unsafe, and unreliable configurations with no apparent recourse."[21] Specifically, the Joint Petition notes concerns with the addition of a statement in R 460.901b(n) that "[replacing] a component with another component that has near-identical characteristics does not constitute a material modification." Michigan EIBC strongly encourages the Commission to reject these arguments and retain the language in R 460.901b(n), including the description of the required review to determine that a modification is material, in the final MIXDG rules.

Throughout the development of the MIXDG rules, Michigan EIBC provided comments emphasizing the importance of ensuring that fair, thorough reviews are conducted to determine whether or not a modification is "material" in nature. It is critical, as is done in the final MIXDG rules, that the Commission spell out clearly in the rules what types of changes are material and what types of changes are not material. This is especially important for projects that go through the study track, given that the time between initial application and approved interconnection agreement can be quite long. As a result, equipment or parts included in an initial application may no longer be available. If that is the case, it is critical that an applicant be able to substitute a "near-identical" component from a different manufacturer, and that such an allowance be clearly indicated in the rules.

Separately, it is critical in the legacy net metering ("LNM") and distributed generation ("DG") section of the MIXDG rules that the addition of energy storage to an existing DG system does

[21] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing. Case No. U-20890. April 14, 2022. p. 13.

not result in an applicant being terminated from the LNM or DG program. The final rules state in R 460.1001 (7)(c) that:

> The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.[22]

It appears that the intention of the Commission is to avoid the situation where a rooftop solar customer in the LNM or DG program with multiple years still left on their agreement is removed from the program when that customer adds an on-site energy storage system. However, if the addition of an energy storage device to an existing LNM or DG program system is considered a material modification (as stated in the final MIXDG rules), it is likely that a utility would require a customer adding an energy storage device to file a new interconnection application, which could trigger removal from the LNM or DG program. However, given that these systems would be export-limited with an inverter or power supply controller, the addition of storage will not increase the generation capacity of the customer's electric generator. As such, based on a plain reading of section 183 of Public Act 342, it would be illegal to remove the customer against their will from the LNM or DG program prior to the end of the grandfathering period.[23] This will become more critical toward the end of 2022 as installations near the DG program caps for both DTE Electric and Consumers Energy. If the relevant DG cap has been reached, a customer who needs to reapply when adding a storage system may find the DG program closed and then may not only not be able to add their storage device, but also, may be unable to continue to use their existing solar panels. If the Commission retains the language in R 460.1001 (7)(c), it is critical that the Commission also clearly confirm that utility procedures must ensure that customers are not harmed.

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[22] Michigan Public Service Commission Order. Case No. U-20890. March 17, 2022. p. 49.
[23] Public Act 342 of 2016. Section 183. Available at: https://www.legislature.mi.gov/documents/2015-2016/publicact/htm/2016-PA-0342.htm.

Simplified Track

In the final MIXDG rules as proposed, the Commission deleted the simplified track, which was a set of limited screens to evaluate level 1 or level 2 projects. Throughout the process to develop the MIXDG rules, Michigan EIBC advocated for and supported the addition of the simplified track. Although the screens in the simplified track were a subset of those included in the fast track, by selecting the screens most critical to evaluate small projects, the simplified track would enable a faster, more streamlined evaluation of the smallest on-site generators that are very unlikely to require additional study.

Michigan EIBC strongly recommends that the Commission retain the simplified track in the MIXDG rules. In addition to the ability to streamline projects, the simplified track also required that the fee for the simplified track plus any LNM or DG program application fee could not together exceed a total of $50. However, with the deletion of the simplified track (as is done in the final MIXDG rules), level 1 and 2 projects would instead go through fast track, which has a fee of $100 + $1/kWac. There is no language in the final MIXDG rules to ensure that a customer would not be charged both a LNM or DG program application fee of $50 plus a fast track fee of $100 + $1/kWac. A customer with a 50 kW level 2 project applying for interconnection under the DG program would have paid $50 in total under the previous version of the MIXDG rules. With the elimination of the simplified track, that same customer may have to pay a $50 application fee for the DG program plus a $150 fee for the fast track, for a total of $200. In addition to the ability to streamline and quickly review level 1 and 2 projects, the retention of the simplified track would provide clear, reasonable, and standard fees for customers. Moreover, increased fees for level 1 customers do nothing to help ensure that middle- and lower-income customers can access DERs. It is these customers who could often benefit most from the long-term savings provided by DERs.

Interconnection Penalties

Michigan EIBC observes that the interconnection penalties provided for in R 460.990 only apply to DERs greater than 100 kW. Smaller systems are more frequently associated with smaller customers, who are less likely to have the resources to protect their right to interconnect under the MIXDG rules. Allowing an electric utility to impede interconnection for smaller systems without consequences sends the wrong message to utilities and treats smaller customers as second-class customers. Michigan EIBC recommends that the Commission revise R 460.990 to remove 100 kW limitation on the availability of penalties as follows:

> R 460.990 Interconnection penalties.
>
> Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER ~~greater than 100 kW~~ to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

Recommended Clarifications

As the Commission considers further comments on the MIXDG rules, Michigan EIBC suggests certain clarifications to improve the rules and facilitate interconnection.

First, related to informal mediation under R 460.904, rule 4(3) provides that the parties to an interconnection dispute may request informal mediation by a Commission interconnection ombudsperson. The rule, however, does not specify any timeframe by when such informal mediation must occur. Because time is often important to the interconnection process and the MIXDG rules *require* other dispute resolution steps that may be needed before an interconnection dispute is resolved, Michigan EIBC suggests that the Commission require an initial meeting with the ombudsperson within 10 days of the request for informal mediation being submitted. The absence of such language may unnecessarily prolong the resolution of an interconnection dispute. Specifically, Michigan EIBC recommends that Rule 4(3) be revised as follows:

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall **commence within 10 days of submission of the written request and** be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

Second, related to R 460.906 and the provisions governing formal mediation, rule 6(1) provides that if “the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:” This language implies that informal mediation is required, but R 460.904 clearly characterizes informal mediation as voluntary after the direct discussion and informal negotiation required under Rule 4(2). Because time is often important in interconnection, Michigan EIBC agrees with treating informal mediation as an optional step in the dispute resolution process. To remedy this inconsistency with R 460.904, Michigan EIBC recommends revising Rule 6(1) of R 406.906 to read as:

(1) If the parties have been unable to resolve a dispute through **either the required direct discussion or informal negotiation or** the **voluntary** informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

Third, we recommend a revision related to R 460.910, which provides for waivers. As written, Rule 10 is ambiguous as to which party has the burden of demonstrating the necessity of a waiver, the duration of any waiver, and the circumstances under which a waiver may be granted. Michigan EIBC proposes deleting the existing Rule 10 and replacing it with the following:

R 460.910 Waivers

Rule 10. (1) The Commission may, on application of an electric utility, customer, alternative electric supplier, or interconnection customer, or on its own motion, grant a temporary or permanent waiver from 1 or more provisions of these rules in situations in which the Commission finds that:

(a) the provision from which the waiver is granted is not statutorily mandated;

(b) there is good cause for the waiver, and it is in the public interest; and

(c) the provision from which the waiver is granted would, as applied in the presented situation, be unreasonable or unnecessarily burdensome.

(2) The burden of proof in establishing a right to a waiver shall be on the party seeking the waiver.

(3) An applicant for a waiver may request expeditious processing.

Fourth, related to interconnection applications under R 460.936, rule 36(7)(b) sets forth the electric utility's obligation to provide a written list of deficiencies in an interconnection application and how such deficiencies are to be addressed. Importantly, however, the rule does not prevent the utility from later adding to the list new, unrelated deficiencies. To prevent a utility from unnecessarily prolonging the interconnection process, the Commission should clarify the rule to confirm the utility's obligation to provide a *comprehensive* list of deficiencies within 10 days of submission of an interconnection application. Michigan EIBC proposes the following modification of Rule 36(7)(b):

> (b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. <u>**A utility may not identify additional deficiencies beyond those originally identified.**</u> If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

Michigan EIBC's final recommendation is related to the requirement in R 460.938 that an electric utility publish on its website a list of interconnection requests it has received. As written, the rule seems to suggest that in a month in which no changes have occurred, no update whatsoever is required to the list. In such situations, it would not be clear whether the lack of an update is due to the lack of any changes or the failure to update the list as required. To avoid any confusion, Michigan EIBC recommends that the rule require a utility to at least update the list to indicate that no changes have occurred since the prior month. Michigan EIBC suggests the following language to reflect this:

> (1) An electric utility shall maintain a publicly available interconnection list, which is available in a sortable spreadsheet format. The sortable spreadsheet must be provided to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly**. If** ~~unless~~ no changes to the spreadsheet have occurred in that month**, a note to that effect must be clearly indicated on the spreadsheet**. The date of the most recent update must be clearly indicated.

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June 27, 2022

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20890 – In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned proceeding, please find **Consumers Energy Company's Comments on Proposed Rule Changes.**

This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Gary A. Gensch, Jr.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.	))))))	Case No. U-20890

<u>CONSUMERS ENERGY COMPANY'S COMMENTS ON PROPOSED RULE CHANGES</u>

I. <u>INTRODUCTION</u>

On March 17, 2022 the Michigan Public Service Commission ("MPSC" or the "Commission") issued an Order responding to the comments and approving a revised version of the Interconnection and Distribution Generation Standards ("MIXDG Rules") for adoption in Case No. U-20890. On April 14, 2022, Consumers Energy Company ("Consumers Energy" or the "Company") and DTE Electric Company ("DTE Electric") filed a joint petition for rehearing of the March 17 Order pursuant to Mich Admin Code, R 792.10437, regarding the MIXDG Rules ("Joint Petition for Rehearing"). On May 12, 2022, the Commission granted the Joint Petition for Rehearing and indicated that it would provide a second public hearing and opportunity to comment on the MIXDG Rules. On May 26, 2022 the Commission issued its Order and Notice of Hearing in Case No. U-20890 ("May 26, 2022 Order") regarding the promulgation of the MIXDG Rules and recission of the legacy Electric Interconnection and Net Metering Standards, Mich Admin Code, R.460.601a *et seq*, which were adopted in the May 26, 2009 Order in Case No. U-15787. The May 26, 2022 Order scheduled a public hearing for June 22, 2022, to allow presentations by interested persons, and set a final deadline for written comments at 5:00 pm on June 27, 2022.

Consumers Energy participated in ten stakeholder sessions addressing potential Interconnection Rules, and five stakeholder meetings addressing potential Distributed Generation rules, hosted by MPSC Staff between December 2018 and March 2020, as directed by the Commission in the November 8, 2018 order in Case No. U-20344. Consumers Energy provided feedback in response to two draft rule sets in strawman proposals on August 28, 2019, and May 1, 2020, respectively. Consumers Energy also provided comments in response to the Commission's September 9, 2021 Order in Case No. U-20890.

In filing these comments in response to the most recent draft of the proposed MIXDG Rules, pursuant to the May 26, 2022 Order, Consumers Energy reiterates its positions and recommendations previously expressed in its comments provided as feedback to strawman proposals on August 28, 2019 and May 1, 2020, and its November 1, 2021 comments in the U-20890 docket, and provides additional comments below.

II. COMMENTS

A. Note on Consumers Energy and DTE Electric Joint Petition for Rehearing

The Company would like to express its appreciation to the Commission for granting the Joint Petition for Rehearing. In the following comments, Consumers Energy will highlight and expand upon several areas of significant concern that necessitate the reversal of much of the language and new definitions added to the MIXDG Rules in the March 17, 2022 Commission Order. If not corrected, these issues will at a minimum result in confusion and disagreements between utilities and applicants for years to come and have the potential to result in safey and reliability concerns to the electric grid as more customers are interconnected over time.

In the alternative, should the Commission elect not to reinstate the language from the version of the MIXDG Rules included as Exhibit B to the Commission's September 9, 2021 Order in this docket ("September 9, 2021 Proposed Rules") as discussed below, where applicable Consumers Energy has also included proposed revisions to the recently revised language in the MIXDG Rules that would reduce the risk of both safety concerns and confusion of interpretation.

In addition to the comments below, Consumers Energy has included a redlined version of the May 26, 2022 MIXDG Rules revisions as Attachment A.

B. R 460.980 – Concerns with Load Offsets and System Protections

The revised version of the MIXDG Rules and definitions reflected in the May 26, 2022 Order requires utilities to study a Distributed Energy Resource ("DER") assuming that the owner will maintain the current load for the lifespan of the DER. The language in R 460.980(4)(a)-(c) could be interpreted by applicants as indicating that if their generation is small relative to their load, that there would not be the possibility of flowback, and they do not need to utilize any protection.

This is a safey and reliability concern because the utility has no control over a customer's load, and how it may change over time. If a customer with a large system significantly reduces load, this increases the amount of flowback to the system that cannot be studied during interconnection. If export capacity increases because minimum load is gone, this could lead to equipment failures and voltage issues. It is not prudent for the utility to study the impact of a DER assuming the current (or future) owner will maintain the minimum load for the lifespan of the DER. The best remedy for this safety and reliability concern is to revert the language in R 460.980 to the language captured in R 460.980 of the September 9, 2021 Proposed Rules, which would include the removal of R 460.980(4)(a)-(c).

If the Commission maintains the requirement in R 460.980 that the utility must study the DER based on load, the Commission should remove the statement in R 460.980(4)(c) that protective functions are not required. Consumers Energy is concerned with R 460.980(4)(c) because the current rules could be interpreted such that no protective relaying is required beyond reverse power protection and minimum import relaying. There are other types of relaying that may be required for the protection of the system, such as fault protective and anti-islanding relaying. If R 460.980(4)(c) is maintained in its current form, then the specific protection functions will need to be specified to clarify that this references R 460.980(4)(a) and (b) only so that it is clear utilities are not precluded from requiring additional standard interconnection protection relaying defined in the utility interconnection procedures.

C. R 460.901a-b and R 460.980 – New Definitions, Rules Allow Battery Generation to be Expanded Without Study

The currently proposed MIXDG Rules added new definitions, including *Limited Export* (R 460.901b(k)) and *Ongoing Operating Capacity* (R 460.901b(x)). The rules also revised the definition of *Material Modification* (R 460.901b(n)). These changes in tandem with new language in R 460.980 *Capacity of the DER* result in permitting battery storage and generation to be expanded as long as the export value remains the same, which is a concern for the safety and reliability of the system.

R 460.980(1) states that "*If the interconnection application requests an increase in capacity for an existing DER,* the *electric utility shall evaluate the application based on the* ***new ongoing operating capacity of the DER***" (emphasis added). The language in R 460.980(4) requires that "*If a DER uses any configuration or operating mode in this subrule to limit the export of electrical power across the point of common coupling,* ***then the generating capacity shall be only the amount capable of being exported not including any inadvertent export***" (emphasis added).

These new definitions and rules operate together to effectively deny a utility's ability to consider the actual size of a proposed interconnection both during the application process and after the application process if the applicant increases nameplate capacity, but the export value is unchanged. The actual size of the interconnection is no longer defined by the actual generation equipment installed, and the utility is not able to consider this in the screening process or perform a more detailed study. This is exacerbated by the potentially overlooked impact of level determination which may cause a project to bypass a necessary study for a generator of a given size. This is a safety and reliability concern because the maximum capacity of an interconnection could be far greater than the export-limited capacity and would dangerously overload the system if export-limiting failed. In order to avoid this safety and reliability concern, the Commission should revert R 460.980 to the previous language in the September 9, 2021 Proposed Rules. Additionally, definitions for “Limited Export,” (R 460.901b(k)), “Ongoing Operating Capacity” (R 460.901b(x)), “Aggregate Capacity” (R 460.901a(d)), “Export Capacity” (R 460.901a(bb)), and “Generating Capacity” (R 460.901a(gg)), should be removed from the Rules to eliminate the potential confusion and safety concern associated with studying a proposed interconnection at its Ongoing Operating Capacity. The definition for “Material Modification” in R 460.901b(n) should also be revised to mirror the definition provided in the September 9, 2021 Propossed Rules as reflected in the Company’s attached redline. The recently revised version of this definition included in the May 26, 2022 Order replaced the term “nameplate rating” with “generating capacity.”

Furthermore, the ability of a generator to use a DER’s limited export to use the non-export track could function in a way that creates confusion and could render this track useless. If a developer is changing the nameplate size of its system, it is unclear how this track would apply. For example, if a generator has 1 MW of aggregate nameplate capacity and 500 kW load, it is unclear whether this would result in the generator considered to have negative 500 kW of capacity. Further clarification is necessary and may result in further Company concern.

D. R 460.980 Capacity of the DER - Concern with Technical Items Defined in Rules, Language Regarding Third-Party Certification of Devices

As indicated on page 8 of the Joint Petition for Rehearing, the revised Rules allow for 30 seconds of "Inadvertent Export" by an interconnected project before it must be brought into compliance in R 460.980. This is a significant amount of time during which a transformer could fail catastrophically, cause a fire, and impact power quality for other customers. This safety concern is exacerbated by the fact that the proposed rules do not allow a utility to consider the actual size of a proposed interconnection both during the application process and after the application process if the applicant increases nameplate capacity, but the export value is unchanged. This means a customer could have a significant amount of nameplate capacity beyond its "ongoing operating capacity" that could be inadvertently exported for up to 30 seconds under the current draft rules.

The best way to rectify this safety and reliability concern is to remove R 460.980(4)(e) from the MIXDG Rules and restore the September 9, 2021 Proposed Rules version of R 460.980, which would include the removal of R 460.980(4). Additionally, the definition of "Inadvertent Export" should be removed. In the alternative, if the Commission elects not to remove R 460.980(4)(e) and the Inadvertent Export definition, the Commission should adjust the language as reflected in Consumers Energy's attached redline of the MIXDG Rules to permit utilities to define the allowable time for "inadvertent export" in their Interconnection and Distributed Generation Procedures. This revision would be consistent with UL 1741 CRD for PCS, which provides that "*the maximum open loop response shall be less than or equal to 30 seconds. Faster PCS response times are allowed and may be required to meet specific utility requirements*." The

30 seconds of inadvertent export is a maximum boundary, and the standard is explicit in allowing utilies to define the appropriate response time to inadvertent export. If the Commission elects to maintain R 460.980(4)(e) in the MIXDG Rules, then Consumers Energy requests this language be updated as described to ensure consistency with UL 1741 CRD for PCS.

Another concern is the language in R 460.980(4)(e) that permits a DER to utilize "*a nationally recognized testing laboratory certified power control system and inverter system* ***that results in the DER disconnecting from the distribution system. . .*** " (emphasis added). This language may lead to confusion and misinterpetation of UL 1741 CRD for PCS. UL 1741 CRD for PCS is a standard for certifying that a device functions to limit export, but this certification *does not* include information on tripping or ceasing to energize. This language in R 460.980(4)(e) appears to assume that the UL 1741 CRD for PCS certification of a device automatically means that the device is certified to "disconnect[ ] from the distribution system" when inadvertent export occurs – but this is not correct. UL 1741 CRD for PCS certification does not indicate that a certified inverter will disconnect from the system or have additional protection from failure when inadvertent export occurs.

To correct this, Consumers Energy reiterates its recommendation that R 460.980(4) should be removed from the Rules. If the Commission elects not to do so, the Commission should strike the language in R 460.980(4)(e) that is not included in UL 1741 CRD for PCS.

E. R 460.901 (a-b) Definitions – Lack of Clarity

The addition of four intertwining definitions (Aggregate Capacity in R 460.901a(d), Export Capacity in R 460.901a(bb), Generating Capacity in R 460.901a(gg), and Ongoing Operating Capacity in R 460.901b(x)) included in the MIXDG Rules broadly impact the rules and are of concern to the Company. These recently added definitions alter what has been considered the baseline for determining project capacity for the duration of the working groups held to discuss the development of updated Interconnection and Distributed Generation Rules and now leave a great deal of ambiguity. Most importantly, the level definitions (R 460.901b(e-i)) were written with an understanding of only one capacity definition, and it is now unclear which of the above definitions applies for determining the project level. This in turn adds confusion about track selection, screening, and study implications. In light of the ambiguity introduced at this stage of a lengthy process, Consumers Energy strongly recommends the removal of these added definitions.

F. R 460.946(4)(b) – Daytime Loading Concerns

The current proposed R 460.946(4)(b) would require an electric utility to "consider 100% of applicable loading, if available, instead of 15% of line section peak load for level 1 and level 2 DER," and also require utilities with 1,000,000 or more customers to collect daytime loading data by January 2023, or as otherwise defined in their procedures. Consumers Energy is concerned with this requirement because remote access to daytime loadings is not readily available on all line sections and the data will be dynamic as meters are exchanged or line sections changed. The dynamic nature of the data will require constant re-calculation to remain valid. Additionally, the requirement to provide this data in an expedited fashion would also result in significant expense to develop this capability. Utilities should only be required to consider using applicable loading as the data becomes available as part of normal business practices. The Company recommends that the Commission remove the language associated with this requirement as indicated in the Company's redline.

G. R 460.946, R 460.950 Concerns with Time to Study Proposed Interconnections, Allowing for Additional Screens

The revised Rules no longer allow utilities to include additional screens in the review process to ensure the safety of a project in R 460.946. If the screens currently included in the Rules are not sufficient and more study is needed, under the current proposed Rules utilities may not have enough time to perform a Facilities Study to further study the project. Future changes or revelations in technology that are not foreseen could require additional screens. If utilities do not have the flexibility in the future, a project could be inadequately reviewed in too short of a time frame under the screens/studies outlined in the Rules, while still posing a safety concern that would be best addressed under an additional utility screen. This need for flexibility is demonstrated, for example, in R 460.946(4)(b) Fast Track; Initial Review. This screen requires the utility to compare a DER's capacity against daytime loading for Level 1 and 2 applicants. This screen is only looking at daytime loading, which would make sense for solar DERs, but may not accurately contemplate non-solar inverter based resources that are certified devices. Examples include wind resources, hybrid resource, and possible future Electric Vehicle ("EV") Programs.

The Company requests this flexibility be included again in the rules by reinstating language from the September 9, 2021 Proposed Rules permitting this flexibility to address issues that may not be seen now. The reinstated language is captured in the Company's redline of the proposed MIXDG Rules under *R 460.950 Fast track: supplemental review* and *R 460.946 Fast track; initial review*.

Additionally, the Rules no longer permit a utility to perform screens for Level 1 and Level 2 non-export DER applications in R 460.946 in several circumstances. Consumers Energy is concerned that excluding Level 1 and/or Level 2 applications from screening inhibits utilities from exercising the flexibility to review smaller projects that may be aggregated, and in aggregate could pose safety and reliability concerns to the system. For this reason, Consumers Energy requests the corresponding language in 460.946(4)(b), (d), and (e) be removed as reflected in the Company's redline.

H. R 460.942 Non-Export Track Review - Concerns with Time to Study Proposed Interconnections

Consumers Energy realized while reviewing the revised MIXDG Rules for implementation that the R 460.942 *non-export track review* will need to be modified to provide clarity that a project that passess screens which may still be a safety concern may undergo a facilities study. Specificially, R 460.942(4)(a) is conditioned upon "**no interconnection facilities, distribution upgrades**, further study, or application modifications" (emphasis added), but the greater non-export track process only addresses further study and application modification requirements. Including such language would be consistent with R 460.946(5) in the *fast track; initial review*. The current language in R 460.942 makes it unclear if utilities will have sufficient time to study proposed interconnections or have the ability to perform a more detailed facilities study if safety concerns are present. It is unclear if this difference between the non-export track and fast track was intentional. Given the difference between the fast track and non-export track review, depending on the procedural review track of a given project, the Rules may not provide sufficient time for the utility to complete a facility study of a project in the non-export track if needed.

While the Company understands the desire for a speedy review process, to ensure safety and reliability of the system, it is critical that this is balanced against a need to have sufficient time to study applications. Newly added language regarding export-limiting, inverter safety, and system protections creates additional challenges in ensuring the safety of proposed projects, and these concerns are further heightened when coupled with current timelines and screening limitations. As technology continues to advance, it is important that utilities have the ability to review new and unique configurations to ensure safety of personnel and the system.

The Company recommends that the MIXDG Rule language is made consistent between the fast track and non-export track study regarding the ability to transition the study to a Facilities

Study. These recommended updates are included in R 460.942 in Consumers Energy's redlined copy of the MIXDG Rules.

Additionally, in R 460.942 *Non-export track review*, the Company recommends the removal of language permitting screens to be used to waive interconnection faclities, distribution upgrades, or application modifications. The Company notes that these screens are meant to determine project eligibility for the non-export track, and not to waive the aforementioned items.

I. Additional Comments

In R 460.942(1), the language in the first sentence was revised in the most recent draft of the Rules to state that "*Interconnection applications for DERs that will limit injection of electric energy…are eligible for evaluation under the non-export track*." The Company recommends that this language be adjusted to state that ""*Interconnection applications for DERs that will **not inject** electric energy…are eligible for evaluation under the non-export track*" as reflected in the Company's redline. This change is necessary because applications that *limit* injection are eligible under the fast-track process, whereas the non-export track was created for applications that *will not* inject - i.e. non-export.

In R 460.942(4), the Company's redline reflects recommended changes to the last sentence. As indicated in the redline comments in the margin, the non-export track review screens are meant to determine project elgibility for the non-export track and should not be used to waive interconnection facilities, distribution upgrades, or application modificatons.

If the Commission does not remove language from R 460.946(4)(b) as reflected in the Company's redline comments, Consumers Energy requests further clarifiation of language stating that "*the electric utility shall consider 100% of applicable loading, if available, instead of 15% of line section peak load for level 1 and 2 DER*." The Company believes that the first value should be 33% rather than 100%. The "*15% of line section peak load for level 1 and 2 DER*" appears to be referring to the anti-islanding screen. If that is correct, this 15% threshold comes from calculating minimum load based on 45% of peak load multiplied by the 33% anti-islanding ratio typically applied to synchronous generators. Multiplying the two percentages (45% and 33%) arrives at 15%. Based on this technical derivation, Consumers Energy believes the value of "100%" should be adjusted to "33%" as reflected in the Company's redlined comments.

Lastly, beyond comments included above on R 460.980 *Capacity of the DER*, if the Commission elects not to revert the section to the language included in the September 9, 2021 Proposed Rules, the Company has included additional comments in its redline for consideration to update language in R 460.980(4).

Respectfully submitted,

CONSUMERS ENERGY COMPANY

ATTACHMENT A

DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS

PUBLIC SERVICE COMMISSION

INTERCONNECTION AND DISTRIBUTED GENERATION STANDARDS

Filed with the secretary of state on

These rules take effect immediately upon filing with the secretary of state unless adopted under section 33, 44, or 45a(9) of the administrative procedures act of 1969, 1969 PA 306, MCL 24.233, 24.244, or 24.245a. Rules adopted under these sections become effective 7 days after filing with the secretary of state.

(By authority conferred on the public service commission by section 7 of 1909 PA 106, MCL 460.557, section 5 of 1919 PA 419, MCL 460.55, sections 4, 6, and 10e of 1939 PA 3, MCL 460.4, 460.6, and 460.10e, and section 173 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173)

R 460.901a, R 460.901b, R 460.902, R 460.904, R 460.906, R 460.908, R 460.910, R 460.911, R 460.920, R 460.922, R 460.924, R 460.926, R 460.928, R 460.930, R 460.932, R 460.934, R 460.936, R 460.938, R 460.940, R 460.942, R 460.944, R 460.946, R 460.948, R 460.950, R 460.952, R 460.954, R 460.956, R 460.958, R 460.960, R 460.962, R 460.964, R 460.966, R 460.968, R 460.970, R 460.974, R 460.976, R 460.978, R 460.980, R 460.982, R 460.984, R 460.986, R 460.988, R 460.990, R 460.991, R 460.992, R 460.1001, R 460.1004, R 460.1006, R 460.1008, R 460.1010, R 460.1012, R 460.1014, R 460.1016, R 460.1018, R 460.1020, R 460.1022, R 460.1024, and R 460.1026 are added to the Michigan Administrative Code, as follows:

PART 1. GENERAL PROVISIONS

R 460.901a Definitions; A-I.
Rule 1a. As used in these rules:
(a) “AC” means alternating current at 60 Hertz.
(b) “Affected system” means another electric utility’s distribution system, a municipal electric utility’s distribution system, the transmission system, or transmission system-connected generation which may be affected by the proposed interconnection.
(c) “Affiliate” means that term as defined in R 460.10102(1)(a).
~~(d) “Aggregate capacity” or “aggregate generation capacity” means the aggregated ongoing operating capacities of all DERs across multiple points of common coupling, within a defined portion of the distribution system.~~
(e) “Alternative electric supplier” means that term as defined in section 10g of 1939 PA 3, MCL 460.10g.

(f) “Alternative electric supplier distributed generation program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's distributed generation program.

(g) “Alternative electric supplier legacy net metering program plan” means a document supplied by an alternative electric supplier that provides detailed information to an applicant about the alternative electric supplier's legacy net metering program.

(h) “Applicant” means the person or entity submitting an interconnection application, a legacy net metering program application, or a distributed generation program application. An applicant is not required to be an existing customer of an electric utility. An electric utility is considered an applicant when it submits an interconnection application for a DER that is not a temporary DER.

(i) “Application” means an interconnection application, a legacy net metering program application, or a distributed generation program application.

(j) “Area network” means a location on the distribution system served by multiple transformers interconnected in an electrical network circuit.

(k) “Business day” means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., excluding electric utility holidays and any day in which electric service is interrupted for 10% or more of an electric utility’s customers. A list of electric utility holidays shall be provided in the electric utility’s interconnection procedures.

(l) “Calendar day” means every day including Saturdays, Sundays, and holidays.

(m) “Certified” means an inverter-based system has met acceptable safety and reliability standards by a nationally recognized testing laboratory in conformance with IEEE 1547.1-2020 and the UL 1741 September 28, 2021 edition except that prior to January 1, 2023, inverter-based systems which conform to the UL 1741SA September 7, 2016 edition are acceptable.

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

(o) “Commissioning test” means the test and verification procedure that is performed on a device or combination of devices forming a system to confirm that the device or system, as designed, delivered, and installed, meets the interconnection and interoperability requirements of IEEE 1547-2018. A commissioning test must include visual inspections and may include, as applicable, an operability and functional performance test and functional tests to verify interoperability of a combination of devices forming a system.

(p) “Conforming” means the information in an interconnection application is consistent with the general principles of distribution system operation and DER characteristics.

(q) “Customer” means a person or entity who receives electric service from an electric utility’s distribution system or a person who participates in a legacy net metering or distributed generation program through an alternative electric supplier or electric utility.

(r) “DC” means “direct current.”

(s) “Distributed energy resource” or “DER” means a source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage devices capable of exporting active power to a distribution system.

(t) “Distributed generation program” means the distributed generation program approved by the commission and included in an electric utility’s tariff pursuant to section

6a(14) of 1939 PA 3, MCL 460.6a, or established in an alternative electric supplier distributed generation program plan.

(u) "Distribution system" means the structures, equipment, and facilities owned and operated by an electric utility to deliver electricity to end users, not including transmission and generation facilities that are subject to the jurisdiction of the federal energy regulatory commission.

(v) "Distribution upgrades" mean the additions, modifications, or improvements to the distribution system necessary to accommodate a DER's connection to the distribution system.

(w) "Electric utility" means any person or entity whose rates are regulated by the commission for selling electricity to retail customers in this state. For purposes of R 460.901a through R 460.992 only, "electric utility" includes cooperative electric utilities that are member regulated as provided in section 4 of the electric cooperative member-regulation act, 2008 PA 167, MCL 460.34.

(x) "Electrically coincident" means that 2 or more proposed DERs associated with pending interconnection applications have operating characteristics and nameplate capacities which require that distribution upgrades will be necessary if the DERs are installed in electrical proximity with each other on a distribution system.

(y) "Electrically remote" means a proposed DER is not electrically coincident with a DER that is associated with a pending interconnection application.

(z) "Eligible electric generator" means a methane digester or renewable energy system with a generation capacity limited to a customer's electric need and that does not exceed either of the following:

(i) 150 kWac of aggregate generation at a single site for a renewable energy system.

(ii) 550 kWac of aggregate generation at a single site for a methane digester.

(aa) "Energy storage device" means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For purposes of these rules, an energy storage device may be considered a DER.

~~(bb) "Export capacity" means the maximum possible simultaneous generation of the DER, and is calculated as the maximum amount of export as permitted by limiting the amount of the DER's export at the point of common coupling.~~

(cc) "Facilities study" means a study to specify and estimate the cost of the equipment, engineering, procurement, and construction work if distribution upgrades or interconnection facilities are required.

(dd) "Fast track" means the procedure used for evaluating a proposed interconnection that makes use of screening processes, as described in R 460.944 to R 460.950.

(ee) "Force majeure event" means an act of God; labor disturbance; act of the public enemy; war; insurrection; riot; fire, storm, or flood; explosion, breakage, or accident to machinery or equipment; an emergency order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities; or another cause beyond a party's control. A force majeure event does not include an act of negligence or intentional wrongdoing.

(ff) "Full retail rate" means the power supply and distribution components of the cost of electric service. Full retail rate does not include a system access charge, service charge, or other charge that is assessed on a per meter, premise, or customer basis.

~~(gg) "Generating capacity" means the maximum nameplate rating of a DER in alternating current, except that where this capacity is limited by any of the methods of limiting electrical export, generating capacity shall be the net capacity as limited though the use of such methods not including inadvertent export.~~

(hh) "Good standing" means an applicant has paid in full all undisputed bills rendered by the interconnecting electric utility and any alternative electric supplier in a timely manner and none of these bills are in arrears.

(ii) "Governmental authority" means any federal, state, local, or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that this term does not include the applicant, interconnection customer, electric utility, or any affiliate thereof.

(jj) "GPS" means global positioning system.

(kk) "Grid network" means a configuration of a distribution system or an area of a distribution system in which each customer is supplied electric energy at the secondary voltage by more than 1 transformer.

(ll) "High voltage distribution" means those parts of a distribution system that operate within a voltage range specified in the electric utility's interconnection procedures. For purposes of these rules, the term "subtransmission" means the same as high voltage distribution.

(mm) "IEEE" means institute of electrical and electronics engineers.

(nn) "IEEE 1547-2018" means "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," as adopted by reference in R 460.902.

(oo) "IEEE 1547.1-2020" means IEEE "Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces," as adopted by reference in R 460.902.

(pp) "Inadvertent export" means the potential condition in which a ~~normally non-exporting or~~ limited-exporting DER experiences an unscheduled export that ~~does not~~ exceeds the limited-export value ~~limitations in terms of magnitude or~~ for less than the duration ~~as~~ specified in UL 1741 CRD for PCS.

Commented [A1]: The Company's first preference and recommendation is for the deletion of this definition per Consumers Energy's comments. If the Commission elects not to remove this definition, the edit shown is recommended with the following comment:

The UL 1741 CRD for PCS does not specify a magnitude limitation above the limited-export value. For certification, it specifies the time that the unscheduled export must fall below the power limited value. The standard states the time frame is 30 seconds unless defined by the utility. For example, a 20kW DER power limited to 10kW could pass certification if it had a 20kW inadvertent export for less than the timeframe defined in the standard.

(qq) "Independent system operator" means an independent, federally-regulated entity established to coordinate regional transmission in a non-discriminatory manner and to ensure the safety and reliability of the transmission and distribution systems.

(rr) "Initial review" means the fast track initial review screens described in R 460.946.

(ss) "Interconnection" means the process undertaken by an electric utility to construct the electrical facilities necessary to connect a DER with a distribution system so that parallel operation can occur.

(tt) "Interconnection agreement" means an agreement containing the terms and conditions governing the electrical interconnection between the electric utility and the applicant or interconnection customer. Where construction of interconnection facilities or distribution upgrades are necessary, the agreement shall specify timelines, cost estimates, and payment milestones for construction of facilities and distribution upgrades to interconnect a DER into the distribution system, and shall identify design, procurement, installation, and construction requirements associated with installation of the DER. Standard level 1, 2, and 3 interconnection agreements and level 4 and 5 interconnection agreements are types of interconnection agreements.

(uu) "Interconnection coordinator" means a person or persons designated by the electric utility who shall serve as the point of contact from which general information on the application process and on the affected system or systems can be obtained through informal request by the applicant or interconnection customer.

(vv) "Interconnection customer" means the person or entity, which may include the electric utility, responsible for ensuring a DER is operated and maintained in compliance with all local, state, and federal laws, as well as with all rules, standards, and interconnection procedures.

(ww) "Interconnection facilities" mean any equipment required for the sole purpose of connecting a DER with a distribution system.

(xx) "Interconnection procedures" mean the requirements that govern project interconnection adopted by each electric utility and approved by the commission.

(yy) "Interconnection study agreement" means an agreement between an applicant and an electric utility for the electric utility to study a proposed DER.

R 460.901b Definitions; J-Z.

Rule 1b. As used in these rules:

(a) "kW" means kilowatt.

(b) "kWac" means the electric power, in kilowatts, associated with the alternating current output of a DER at unity power factor.

(c) "kWh" means kilowatt-hours.

(d) "Legacy net metering program" means the true net metering or modified net metering programs in place prior to commission approval of a distributed generation program tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, and prior to the establishment of an alternative electric supplier distributed generation plan.

(e) "Level 1" means a certified project of 20 kWac or less.

(f) "Level 2" means a certified project of greater than 20 kWac and not more than 150 kWac.

(g) "Level 3" means a project of 150 kWac or less that is not certified, or a project greater than 150 kWac and not more than 550 kWac.

(h) "Level 4" means a project of greater than 550 kWac and not more than 1 MWac.

(i) "Level 5" means a project of greater than 1 MWac.

(j) "Level 4 and 5 interconnection agreement" means an interconnection agreement applicable to level 4 and 5 interconnection applications.

~~(k) "Limited export" means the exporting capability of a DER whose generating capacity is limited by the use of any configuration or operating mode.~~

(l) "Low voltage distribution" means those parts of a distribution system that operate with a voltage range specified in the electric utility's interconnection procedures.

(m) "Mainline" means a conductor that serves as the three-phase backbone of a low voltage distribution circuit.

(n) "Material modification" means a modification to the DER ~~generating capacity~~nameplate rating, electrical size of components, bill of materials, machine data, equipment configuration, or the interconnection site of the DER at any time after receiving notification by the electric utility of a complete interconnection application. ~~Replacing a component with another component that has near-identical characteristics does not constitute a material modification.~~ For the proposed modification to be considered material, it shall have been reviewed and been determined to have or anticipated to have a material impact on 1 or more of the following:

(i) The cost, timing, or design of any equipment located between the point of common coupling and the DER.

(ii) The cost, timing, or design of any other application.

(iii) The electric utility's distribution system or an affected system.

(iv) The safety or reliability of the distribution system.

(o) "Methane digester" means a renewable energy system that uses animal or agricultural waste for the production of fuel gas that can be burned for the generation of electricity or steam.

(p) "Modified net metering" means an electric utility billing method that applies the power supply component of the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system during a billing period or time-of-use pricing period.

(q) "MW" means megawatt.

(r) "MWac" means the electric power, in megawatts, associated with the alternating current output of a DER at unity power factor.

(s) "Nameplate capacity" means the maximum active power, in kWac or MWac, at which a DER is capable of sustained operation.

(t) "Nameplate rating" means all of the following at which a DER is capable of sustained operation:

(i) Nominal voltage (V).

(ii) Current (A).

(iii) Maximum active power (kWac).

(iv) Apparent power (kVA).

(v) Reactive power (kvar).

(u) "Nationally recognized testing laboratory" means any testing laboratory recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration.

(v) "Network protector" means those devices associated with a secondary network used to automatically disconnect a transformer when reverse power flow occurs.

(w) "Non-export track" means the procedure for evaluating a proposed interconnection that will not inject electric energy into an electric utility's distribution system, as described in R 460.942.

~~(x) "Ongoing operating capacity" means the actual simultaneous generating capacity, taking into account the operational differences of load offset and export. If the contribution of energy storage to the total contribution is limited by programing of the maximum active power output, use of a power control system, use of a power relay, or some other mutually agreed upon, on-site limiting element, only the capacity that is designed to inject electricity to the utility's distribution system, other than inadvertent exports and fault contribution, will be used within certain technical screens and evaluations.~~

(y) “Parallel operation” means the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system.

(z) “Party” or “parties” means an electric utility, applicant, or interconnection customer.

(aa) “Point of common coupling” means the point where the DER connects with the electric utility’s distribution system.

(bb) “Power control system” means systems or devices which electronically limit or control steady state currents to a programmable limit and certified under UL 1741 CRD for PCS by a nationally recognized testing laboratory.

(cc) “Radial supply” means a configuration of a distribution system or an area of a distribution system in which each customer can only be supplied electric energy by 1 substation transformer and distribution line at a time.

(dd) “Readily available” means no creation of data is required, and little or no computation or analysis of data is required.

(ee) “Reasonable efforts” mean, with respect to an action required to be attempted or taken by a party under these interconnection rules, efforts that are as timely as possible and consistent with those a party would take to protect its own interests.

(ff) “Regional transmission operator” 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, expansion, operation, and use on a regional and interregional basis.

(gg) “Renewable energy credit” means a credit granted pursuant to the commission's renewable energy credit certification and tracking program in section 41 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1041.

(hh) “Renewable energy resource” means that term as defined in section 11(i) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(ii) “Renewable energy system” means that term as defined in section 11(k) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1011.

(jj) “Secondary network” means those areas of a distribution system that operate at a secondary voltage level and are networked.

(kk) “Site” means a contiguous site, regardless of the number of meters at that site. A site that would be contiguous but for the presence of a street, road, or highway is considered to be contiguous for the purposes of these rules.

(ll) “Spot network” means a location on the distribution system that uses 2 or more inter-tied transformers to supply an electrical network circuit, such as a network circuit in a large building.

(mm) “Standard level 1, 2, and 3 interconnection agreement” means the statewide interconnection agreement approved by the commission and applicable to levels 1, 2 and 3 interconnection applications. A cover sheet including modifications to address any special operating conditions may be added.

(nn) “Study track” means the procedure used for evaluating a proposed interconnection as described in R 460.952 to R 460.962.

(oo) “Supplemental review” means the fast track supplemental review screens described in R 460.950.

(pp) “System impact study” means a study to identify and describe the impacts to the electric utility’s distribution system that would occur if the proposed DER were interconnected exactly as proposed and without any modifications to the electric utility's distribution system. A system impact study also identifies affected systems.

(qq) "Temporary DER" means a DER that is installed on the distribution system by the electric utility with the intention of not operating at the site permanently.

(rr) "True net metering" means an electric utility billing method that applies the full retail rate to the net of the bidirectional flow of kWh across the customer interconnection with the electric utility's distribution system, during a billing period or time-of-use pricing period.

(ss) "UL" means underwriters laboratory.

(tt) "UL 1741" means the September 28, 2021 edition of "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources," as adopted by reference in R 460.902.

(uu) "UL 1741 CRD for PCS" means the Certification Requirement Decision for Power Control Systems for the standard titled Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, March 8, 2019, as adopted by reference in R 460.902(b).

R 460.902 Adoption of standards by reference.

Rule 2. (1) The standards specified in these rules are adopted by reference as follows:

(a) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, September 28, 2021 edition, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/ProductDetail.aspx?productId=UL1741 at a cost of $798.00 at the time of adoption of these rules.

(b) UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources, January 28, 2010 edition, is available from Underwriters Laboratories at the internet website: https://standardscatalog.ul.com/ProductDetail.aspx?productId=UL1741 at a cost of $716.00 at the time of adoption of these rules.

(c) ANSI C84.1 – 2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hz), June 9, 2016, is available from the American National Standards Institute, Inc. at the internet website https://webstore.ansi.org/ at a cost of $111.24 at the time of adoption of these rules.

(d) The following standards adopted by reference are available from IEEE at the internet website https://standards.ieee.org at the time of adoption of these rules.

(i) The IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, October 30, 2015, is available at a cost of $99.00 - $147.00 at the time of adoption of these rules.

(ii) The IEEE 1547 - 2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces, April 6, 2018, is available at a cost of $149.00 - $224.00 at the time of adoption of these rules.

(iii) The IEEE 1547.1-2020 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces, May 21, 2020, is available at a cost of $197.00 - $296.00 at the time of adoption of these rules.

(iv) The IEEE 519-2014 IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems, June 11, 2014, is available at a cost of $52.00 - $66.00 at the time of adoption of these rules.

(2) The commission has copies of the standards specified in subrule (1) of this rule available for review at its offices located at 7109 W. Saginaw Hwy., Lansing, Michigan 48917-1120. The mailing address is Michigan Public Service Commission, P.O. Box 30221, Lansing, Michigan 48909-0221.

R 460.904 Informal mediation.

Rule 4. (1) The parties shall attempt to resolve all disputes arising out of the interconnection process, as defined by R 460.901a through R 460.992, according to the provisions of this rule.

(2) Prior to formal mediation under R 460.906, the parties shall attempt to resolve any conflict without commission intervention through direct discussion and informal negotiation.

(3) In the event that parties are unable to resolve the dispute privately, the parties may, by mutual agreement, make a written request for informal mediation to the commission staff. The informal mediation shall be conducted by an interconnection ombudsperson who shall be a member of the commission staff and designated by the commission. Both parties may choose to have attorneys or appropriate representation present.

(4) During informal mediation, the parties shall discuss relevant facts pertaining to the dispute and the relief being sought. The interconnection ombudsperson and relevant commission staff shall be present to facilitate the discussion and provide guidance among the parties. Parties shall operate in good faith and use best efforts to resolve the dispute.

(5) If a resolution is reached by the end of the meeting or meetings, the parties may draft a resolution of the dispute.

(6) If the parties reach impasse and are unable to resolve the dispute, the parties shall proceed to the formal mediation process described in R 460.906.

R 460.906 Formal mediation.

Rule 6. (1) If the parties have been unable to resolve a dispute through the informal mediation process under R 460.904, the parties shall then attempt to resolve the dispute in the following manner:

(a) The complaining party shall file a written notice of dispute with the commission. The notice of dispute must state the specific grounds for the dispute, sufficient facts to support the allegations, the relief requested, and must contain all information, testimony, exhibits, or other documents and information within the party’s possession on which the party intends to rely to support the party’s position.

(b) The complaining party shall give notice that it is invoking the procedures in this rule. The complaining party shall send the notice to the non-complaining party’s email address and file the notice with the commission.

(c) The non-complaining party shall acknowledge the notice of dispute within 10 business days of its receipt and identify a representative with the authority to make decisions on its behalf with respect to the dispute.

(d) An administrative law judge shall serve as the mediator in these proceedings. The administrative law judge may request and receive assistance from commission staff.
(e) Within 60 business days from the date the non-complaining party acknowledges the dispute, the mediator shall issue a recommended settlement.
(f) Within 5 business days after the date the recommended settlement is issued, each party shall file with the commission a written acceptance or rejection of the recommended settlement. If the parties accept the recommendation, then the recommendation shall become an order. If a party rejects or fails to respond within 5 business days to the recommended settlement, then the dispute may proceed to a contested case hearing before the commission as provided in R 792.10415.
(2) Nothing in these rules precludes a disputing party from filing a formal complaint with the commission, either instead of or after pursuing informal mediation or formal mediation pursuant to these rules.
(3) The initiation of any form of dispute resolution by a party tolls any applicable deadlines under these rules until the dispute is resolved.

R 460.908 Timelines for electric utilities serving fewer than 1,000,000 in-state customers.
Rule 8. An electric utility serving fewer than 1,000,000 in-state customers shall have an additional 10 business days to comply with the timelines in R 460.911 to R 460.1026. This rule does not apply to applicants or interconnection customers.

R 460.910 Waivers.
Rule 10. An electric utility, customer, alternative electric supplier, applicant, or interconnection customer may apply to the commission for a waiver from 1 or more provisions of these rules and may request expeditious processing. The commission may grant a waiver upon a showing of good cause and a finding that the waiver is in the public interest.

PART 2. INTERCONNECTION STANDARDS

R 460.911 Applicability.
Rule 11. These rules apply to all interconnection applications filed on or after the effective date of these rules. The electric utility shall complete work on any interconnection study agreement executed prior to the effective date of these rules pursuant to the terms and conditions of that interconnection study agreement. Any new studies or other additional work must be completed pursuant to these rules. An electric utility or an alternative electric supplier shall not restrict access to interconnection for level 1, level 2, and level 3 DERs that are not participants in the legacy net metering or distributed generation programs.

R 460.920 Electric utility interconnection procedures.

Rule 20. (1) An electric utility shall file applications for approval of interconnection procedures and forms within 30 business days of the effective date of these rules.

(2) The commission shall issue its order approving, rejecting, or modifying the proposed interconnection procedures and forms within 360 calendar days of the effective date of these rules. If the commission finds the procedures and forms proposed by the electric utility to be inadequate or unacceptable, the commission may either adopt procedures and forms proposed by another person in the proceeding or modify and accept the procedures and forms proposed by the electric utility.

(3) Until the commission accepts, rejects, or modifies an electric utility's interconnection procedures and forms, the electric utility may use the proposed interconnection procedures and forms when processing interconnection applications with the exception of fixed fees and fee caps. An electric utility shall only charge fees that comply with the requirements of R 460.926 until the commission accepts, rejects, or modifies the proposed interconnection procedures and forms unless the commission approves different fees pursuant to R 460.926(4).

(4) Two or more electric utilities may file a joint application proposing interconnection procedures for use by the joint applicants. The proposed interconnection procedures must ensure compliance with these rules.

(5) The proposed interconnection procedures must, at a minimum, include all of the following:

(a) All necessary applications, forms, and relevant template agreements.

(b) A schedule of all applicable fixed fees and fee caps.

(c) Voltage ranges for high voltage distribution and low voltage distribution.

(d) Required initial review screens.

(e) Required supplemental review screens.

(f) The process for conducting system impact studies and facilities studies on DERs when there is an affected system issue.

(g) Testing and certification requirements of DER telecommunications, cybersecurity, data exchange, and remote control operation.

(h) Parallel operation requirements.

(i) A method to estimate the expected annual kWh output of the generator or generators.

(j) Acceptable methods or standards for power-limited export DERs in compliance with allowances in R 460.980.

(k) A cost allocation methodology for study track DERs.

(l) An evaluation of an interconnection application for a project that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling.

(m) Details describing how an energy storage device may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.

(n) For electric utilities that are member-regulated electric cooperatives, a procedure for fairly processing applications in instances in which the number of applications exceed the capacity of the electric cooperative to timely meet the deadlines in these rules.
(o) Examples of modifications that are not material modifications.
(p) The procedure for performing a material modification review to determine if a modification is material.
(q) Any required terms and conditions which must be specified in the general liability insurance for level 3, 4, and 5 projects.
(r) A list of the electric utility's holidays.
(s) If an electric utility uses an alternative process pursuant to R 460.956, a description of that process.
(6) An electric utility shall obtain commission approval to revise its interconnection procedures.

R 460.922 Online applications and electronic submission.
Rule 22. (1) An electric utility shall allow pre-application report requests, interconnection applications, and interconnection agreements to be submitted electronically, such as, through the electric utility's website or via email.
(2) An electric utility shall dedicate a page on its website or direct customers to a linked website with information on these rules. The relevant information available to an applicant or interconnection customer via a website must include all of the following:
(a) These rules and interconnection procedures in an electronically searchable format.
(b) The electric utility's applications and all associated forms in a format that allows for electronic entry of data.
(c) Sample documents including, at a minimum, a 1-line diagram with required labels.
(d) Contact information for the electric utility's DER interconnection coordinator, including an email address and a phone number.
(e) Directions for the submission of applications.

R 460.924 Communications.
Rule 24. (1) An electric utility shall designate 1 or more interconnection coordinators. The telephone number and e-mail address of the interconnection coordinator or coordinators must be made available on the electric utility's website. The interconnection coordinator or coordinators must be available to provide reasonable assistance to the applicant or interconnection customer but is not responsible to directly answer or resolve all of the issues that may arise in the interconnection process.
(2) An applicant may designate an application agent. An application agent may serve as the single point of contact for the applicant and may coordinate with the electric utility on the applicant's behalf. Designation of an application agent does not absolve the applicant from signing interconnection documents or from complying with the requirements in these rules and the interconnection agreement.
(3) An electric utility must be indemnified by the applicant and its application agent with respect to assistance provided by an interconnection coordinator or coordinators.

R 460.926 Fees.

Rule 26. (1) After the effective date of these rules, fees for the pre-application report, the non-export track and the fast track shall be established as listed in subrule (2) of this rule. Initial fees for the study track shall not exceed initial fee caps as established in subrule (3) of this rule. Fees must remain in effect until interconnection procedures are approved by the commission under R 460.920.

(2) The fee amounts for the pre-application report, non-export track, and fast track for all levels of DERs are as follows:

(a) The pre-application report fee may not exceed $300.

(b) The non-export track fee may not exceed $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(c) The fast track initial review fee is $100 + $1/kWac for certified DERs and $100 + $2/kWac for non-certified DERs.

(d) Any applicable legacy net metering program application fee pursuant to R 460.1004(7) or distributed generation program application fee pursuant to R 460.1006(6), together, may not exceed a total of $50.

(3) The initial fee caps for a fast track supplemental review and the study track for all levels of DERs are as follows:

(a) The fee for a fast track supplemental review including all review screens may not exceed $1,000.

(b) The study track fee for interconnection application review and the scoping meeting may not exceed $300.

(c) The system impact study fee may not exceed $10,000.

(d) The facilities study fee may not exceed $15,000.

(4) The fees listed in subrule (2) and initial fee caps listed in subrule (3) of this rule, must be displayed prominently on the electric utility's interconnection website.

(5) An electric utility that expects to incur costs greater than the fees listed in subrule (2) or initial fee caps listed in subrule (3) of this rule in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.928 Fee and fee cap modifications.

Rule 28. (1) An electric utility shall include in its proposed interconnection procedures fixed fees to replace the fees specified in R 460.926(2)(a), (b), and (c), and add any other fixed fees the electric utility considers necessary.

(2) An electric utility shall include in its proposed interconnection procedures adjusted fee caps to replace the initial fee caps specified in R 460.926(3)(a), (b), (c), and (d), and add any other fee caps the electric utility considers necessary. An electric utility may charge actual costs up to the fee caps.

(3) The fixed fees must be specific to level size and be based on estimates of reasonable costs to perform the applicable service or study. The fee caps must be specific to level size and be based on a reasonable range of costs for performing the applicable study.

(4) The most recently approved fixed fees and fee caps must be listed in the electric utility's interconnection procedures and displayed prominently on the electric utility's interconnection website.

(5) The fixed fees and fee caps that are approved for inclusion in the electric utility's interconnection procedures by the commission may be reviewed at any time by the electric utility and adjusted, if necessary, subject to commission review and approval.
(6) Any modification of fees may not be applicable to fees already paid.
(7) An electric utility that expects to incur costs greater than its prevailing fee caps in the evaluation of an interconnection application may file a request for a waiver pursuant to R 460.910.

R 460.930 Pre-application report request form.
Rule 30. (1) An applicant shall submit a completed pre-application report request form and the required fee for a pre-application report on a proposed level 4 or level 5 DER.
(2) The pre-application report request form must include all of the following information:
(a) Project contact information, including name, address, phone number, and email address.
(b) Project location, as accurately as can be identified, which may be given by any of the following:
(i) Street address with nearby cross streets and town.
(ii) An aerial map with location clearly marked.
(iii) GPS coordinates.
(c) Account number, meter number, structure number, or other equivalent information identifying the proposed point of common coupling, if available.
(d) Whether the DER is any of the following:
(i) Solar.
(ii) Wind.
(iii) Cogeneration.
(iv) Storage.
(v) Solar with storage.
(vi) Other type of DER.
(e) Capacity of the DER types in alternating current kW and kVA, and kWh for storage.
(f) Whether the DER configuration is single or 3-phase.
(g) Whether the DER will be a stand-alone generator, meaning no onsite load other than station service.
(h) Whether the DER will be certified.
(i) Whether new service is requested. If there is existing service, the customer account number and site minimum and maximum current or proposed electric loads in kW, if available, must be included, and how the load is expected to change must be specified.
(j) Whether the location is new construction.

R 460.932 Pre-application report.
Rule 32. (1) Using the information provided in the pre-application report request form described in R 460.930, an electric utility shall identify the substation bus, bank, or circuit most likely to serve the point of common coupling. This identification by the

electric utility does not necessarily indicate that this would be the circuit to which the project ultimately connects.

(2) An applicant may request additional pre-application reports if information about multiple points of common coupling is requested. No more than 10 pre-application report requests may be submitted by an applicant and its affiliates during a 1-week period. An electric utility may reject additional pre-application report requests.

(3) The pre-application report must include all of the following information:

(a) Total capacity, in MW, of substation bus, bank, or circuit based on normal or operating ratings likely to serve the proposed point of common coupling.

(b) Existing aggregate generation capacity, in MW, interconnected to a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(c) Aggregate capacity, in MW, of generation not yet built but found in previously accepted interconnection applications, for a substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(d) Available capacity, in MW, of substation bus, bank, or circuit likely to serve the proposed point of common coupling.

(e) Substation nominal distribution voltage.

(f) Nominal distribution circuit voltage at the proposed point of common coupling.

(g) Label, name, or identifier of the distribution circuit on which the proposed point of common coupling is located.

(h) Approximate circuit distance between the proposed point of common coupling and the substation.

(i) The actual or estimated peak load and minimum load data at any relevant line section or sections, including daytime minimum load and absolute minimum load, when available. If not readily available, the report must indicate whether the generator is expected to exceed minimum load on the circuit.

(j) Whether the point of common coupling is located behind a line voltage regulator and whether the substation has a load tap changer.

(k) Limiting conductor ratings from the proposed point of common coupling to the distribution substation.

(l) Number of phases available at the primary voltage level at the proposed point of common coupling, and, if a single phase, distance from the 3-phase circuit.

(m) Whether the point of common coupling is located on a spot network, area network, grid network, radial supply, or secondary network.

(n) Based on the proposed point of common coupling, the report must indicate whether power quality issues may be present on the circuit.

(o) Whether or not the area has been identified as having a prior affected system.

(p) Whether or not the site will require a system impact study for high voltage distribution based on size, location, and existing system configuration.

(4) The pre-application report may include only existing and readily available data. A request for a pre-application report does not obligate an electric utility to conduct a study or other analysis of the proposed DER if data is not readily available. The pre-application report must also indicate any information listed in subrule (3) of this rule that is not readily available. An electric utility may, at its discretion, return any portion of the pre-application report fee because some or all information does not exist.

(5) Pre-application report requests must be processed in the order in which an electric utility received the requests.
(6) An electric utility shall provide the data required in the pre-application report to the applicant within 20 business days of receipt of the completed request form and payment of the fee. The pre-application report produced by the electric utility is non-binding and does not confer any rights on the applicant.

R 460.934 Site control.

Rule 34. (1) Documentation of site control must be submitted with the application by the applicant.
(2) For level 3, 4, or 5 DERs, site control may be demonstrated by providing documentation that shows any of the following:
(a) Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing and operating the DER.
(b) An enforceable option to purchase or acquire a leasehold site for this purpose.
(c) A legally binding agreement transferring a present real property right to specified real property along with the right to construct and operate a DER on the specified real property for a period of time not less than 5 years.
(3) For level 1 or 2 DERs, proof of site control may be demonstrated by the site owner's signature and contact information on the application.
(4) An applicant may redact commercially sensitive information from site control documents.

R 460.936 Interconnection applications.

Rule 36. (1) An electric utility shall provide an interconnection application for an applicant to complete, including for those applicants whose DERs will be configured to be non-exporting.
(2) All documents required for a complete interconnection application must be listed on the interconnection application. For level 4 and 5 interconnection applications, the list of required documents must include a completed pre-application report.
(3) For interconnection applications with proposed DERs that fall into level 1, an applicant shall provide a 1-line diagram and a site diagram.
(4) For interconnection applications with proposed DERs that fall into levels 2 and 3, an applicant shall provide a 1-line diagram that is either sealed by a professional engineer licensed in this state or signed by an electrical contractor who is licensed in this state with the electrical contractor's license number noted on the diagram. An applicant shall also provide a site diagram.
(5) For interconnection applications with proposed DERs that fall into levels 4 and 5, an applicant shall provide a 1-line diagram that is sealed by a professional engineer who is licensed in this state. An applicant shall also provide a site diagram.
(6) Applications shall be reviewed to assess whether they are complete and conforming in the order in which they were received. An application is considered received when an electric utility receives the application, the application's attachments, and the application fee. The application must be date-stamped for the first business day when the electric

utility has received the interconnection application, the application attachments, and payment of the application fee. An electric utility shall notify the applicant of receipt of the application by the end of the third business day following the date of the date stamp.

(7) The electric utility shall notify the applicant that the interconnection application is either complete and conforming, or incomplete, or non-conforming, within 10 business days of the date stamp.

(a) If an interconnection application is determined to be complete and conforming by the electric utility, the applicant must be notified that the interconnection application is accepted. The electric utility shall also indicate whether the interconnection application will be processed using the non-export track, fast track, or study track.

(b) If the application is incomplete or non-conforming, the electric utility shall provide to the applicant a written list of all deficiencies with the notification. The applicant shall have 60 business days from the date of electric utility notification to submit the necessary information and may provide up to 2 submissions during this time period. After each submission of information, the electric utility shall have 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this rule, the utility may withdraw the application.

(8) An electric utility shall comply with part 2 of these rules, R 460.911 to R 460.992, and its interconnection procedures when interconnecting DERs that it owns and operates onto its distribution system, with the exception of temporary DERs.

(9) An electric utility shall use the same process when processing and studying interconnection applications from all applicants, whether the DER is owned or operated by the electric utility, its subsidiaries or affiliates, or others, with the exception of temporary DERs.

(10) An electric utility shall review and update interconnection applications periodically to reflect new information required to properly review DERs, subject to commission review and approval.

R 460.938 Public interconnection list.

Rule 38. (1) An electric utility shall maintain a publicly available interconnection list, which is available in a sortable spreadsheet format. The sortable spreadsheet must be provided to the public upon request. An electric utility that has received not less than 100 complete interconnection applications in a year shall publish this list on the electric utility's website. The public interconnection list must be updated monthly unless no changes to the spreadsheet have occurred in that month. The date of the most recent update must be clearly indicated.

(2) The public interconnection list must include all of the following:

(a) An application identifier.

(b) The date that the electric utility received the application.

(c) The date that the electric utility considered the application to be complete and conforming.

(d) Whether the application is on the non-export track, fast track, or study track.

(e) The proposed DER nameplate capacity.

(f) The proposed DER interconnection size level.

(g) The DER technology type.
(h) The county and township in which the proposed point of common coupling will be located.
(i) The current status of the application's progress in the interconnection process.
(j) The labels, names, or identifiers of the distribution circuit and substation.

R 460.942 Non-export track review.

Rule 42. (1) Interconnection applications for DERs that will not inject ~~limit injection of~~ electric energy into an electric utility's distribution system are eligible for evaluation under the non-export track. Non-export eligibility requires an existing electrical service at the applicant's premise.

(2) Subject to review and approval by the commission, an electric utility may limit the eligibility of the non-export track in its interconnection procedures based on the characteristics of its distribution system.

(3) Before submitting an interconnection application, a non-export track applicant may contact the electric utility for assistance in determining whether a non-export track review will be sufficient or the study track is necessary. The electric utility shall provide the applicant assistance based on available information. If the applicant chooses to proceed, an interconnection application shall be submitted pursuant to R 460.936.

(4) Within 20 business days after being notified that the application was accepted, the electric utility shall perform an initial review by using some or all of the initial review screens specified in the electric utility's interconnection procedures and notify the applicant of the results. If an electric utility chooses to perform a review using a subset of the initial review screens, the exclusion of 1 or more screens may not be the only basis for the electric utility to require ~~interconnection facilities, distribution upgrades,~~ further study~~, or application modifications~~.

(5) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection application must proceed under R 460.962.

(6) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.
(b) Proceed to supplemental review under R 460.950.
(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify

Commented [A2]: The language was modified from "will not inject" to "will limit injection" in the latest revision. Applications that limit injection are eligible under the fast-track process. The non-export track was created for applications that will not inject (non-export). The Company recommends the previous language reflected in this edit be reinstated.

Commented [A3]: The Company notes that the screens are meant to determine project eligibility for the non-export track and the Company recommends that they should not be used to waive interconnection facilities, distribution upgrades, or application modifications.

the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (4) of this rule.

(d) Withdraw the interconnection application.

(7) If the applicant does not select a course of action under subrule (6) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

~~(a) If the notification indicates that no interconnection facilities, distribution upgrades, further study, or application modifications are required, the electric utility shall provide specifications for any equipment the applicant will be required to install within 20 business days of the applicant being notified. Within 10 business days of receiving the equipment specifications, the applicant shall notify the electric utility whether it will proceed under R 460.964 to an interconnection agreement or will withdraw the application. The applicant's failure to notify the electric utility within the required time period shall result in the interconnection application being withdrawn by the electric utility.~~

~~(b) If application modification is offered by the electric utility, the applicant shall either withdraw the interconnection application or provide a modified application within 60 business days from the date of electric utility notification, with up to 2 resubmissions during this time period to provide a modified application. After each submission of information, the electric utility shall notify the applicant within 10 business day that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. When the applicant provides a modified application, the electric utility shall follow the procedure specified in subrule (4) of this rule.~~

~~(5) If further study is required, the electric utility shall present options and the applicant shall decide whether to proceed to a supplemental review under R 460.950, or to the study track under R 460.952, or to withdraw the application. The applicant shall have 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification, the electric utility may withdraw the application within the required time period.~~

~~(6) When an applicant changes from a non-exporting system to an exporting system, the applicant shall submit a new interconnection application.~~

Commented [A4]: R 460.942 does not address what happens if interconnection facilities or distribution upgrades are required. It is unclear to Consumers Energy why R 460.942(4)(a) through the end of the section differ from the related fast track process in R 460.946(5-7) that appears to accomplish the same purpose more thoroughly. The Company believes it would be simpler to implement one process rather than two separate but similar processes. The Company recommends the language in 460.942(4)(a) be revised to reflect the fast track process. Please see the Company's recommend edits as reflected in items 5-7 of this section.

R 460.944 Fast track applicability.

Rule 44. (1) Level 1, level 2, level 3, and level 4 applications and level 5 applications as large as 5 MWac in which the DER is not proposing to interconnect with the electric utility's high voltage distribution system are eligible for the fast track. Applications that provide for the use of an energy storage device so the export of power meets the requirements of level 1, level 2, level 3, level 4 or level 5 as large as 5 MWac in which

Commented [A5]: Consumers Energy is concerned about the expansion of fast track eligibility above 1 MW. While this feels like an expansion of customer eligibility, the Company's experience has indicated it to be highly unlikely for a 5 MW project to pass fast track screens for a Consumers Energy interconnection. This would result in customer frustration as well as wasted time and effort on the part of both parties before eventually placing the project in the appropriate study track.

the applicant is not proposing to interconnect the DER with the electric utility's high voltage distribution system are also eligible for the fast track.

(2) An applicant that is eligible for the fast track may forgo the fast track and proceed directly to the study track.

(3) An applicant with an application that is outside the limitations specified in subrule (1) of this rule may petition the electric utility to have its application evaluated under fast track. The electric utility may approve or reject this request at its discretion.

(4) In determining fast track eligibility, an electric utility may aggregate all proposed new generation on a site regardless of the existence of a shared point of common coupling or multiple points of common coupling.

R 460.946 Fast track; initial review.

Rule 46. (1) An electric utility shall list in its interconnection procedures the initial review screens specified in subrule (4) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(x) An electric utility may include additional initial review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, an electric utility shall provide a detailed technical rationale for including each additional screen. If an additional screen conflicts with or undermines any of the initial review screens specified in subrule (4) of this rule, the rationale must include an explanation of how it does so.

(2) The electric utility may waive application of 1, some, or all of the initial review screens.

(3) Within 10 business days after an electric utility receives a complete and conforming level 1 or level 2 application and associated payment, or within 20 business days after an electric utility receives a complete and conforming level 3, level 4, or level 5 application and associated payment, the electric utility shall perform an initial review and notify the applicant of the results. The initial review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (2) of this rule to the proposed DER. The electric utility shall not require a supplemental review or a system impact study if the DER passes the applied initial review screens.

(4) The initial review screens are all of the following:

(a) The entire proposed DER, including all aggregated site generation and point or points of interconnection, must be located within the electric utility's service territory.

(b) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the circuit may not exceed 15% of the line section annual peak load as most recently measured or calculated if measured data is not available. A line section is that portion of an electric utility's distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. ~~The electric utility shall consider 100% of applicable loading, if available, instead of 15% of line section peak load for level 1 and level 2 DER. In the event daytime loading data is not available, the data must be collected by January 2023 for electric utilities with more than 1,000,000 customers in this state, or by a date specified in interconnection procedures approved by the commission for electric utilities~~

Commented [A6]: The Company recommends this previously deleted language that allows utilities to include additional screens in its interconnection procedures be reinstated.

Commented [A7]:
The Company's first preference is the removal of the language stricken in this paragraph.

If the Commission elects not to strike this language, Consumers Energy is assuming the 15% reflect here is referencing the anti-islanding screen. The 15% threshold comes from calculating min load based on 45% of peak load multiplied by the 33% islanding ratio typically applied to synch generators (0.45x0.33=0.15). Based on this technical derivation, Consumers Energy believes this value should be 33%.

The Company requests that the Commission clarify if the value should be 33%, not 100%, based on the technical derivation of the 15% value?

~~with fewer than 1,000,000 customers in this state, and shall not consider as part of the aggregate generation, for purposes of this screen, DER capacity known to be already reflected in the minimum load data. This screen does not apply to level 1 and level 2 non-export DER applications.~~

(c) For interconnection of a proposed DER to the load side of network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DERs, may not exceed the smaller of 5% of a network's maximum load or 50 kWac.

(d) The proposed DER, in aggregation with other DERs on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum fault current at the point on the primary voltage nearest the proposed point of common coupling. ~~This screen does not apply to level 1 applications.~~

(e) The proposed DER, in aggregate with other DERs on the distribution circuit, may not cause any distribution protective devices and equipment or interconnection customer equipment on the system to exceed 87.5% of the short circuit interrupting capability. An interconnection may not be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. Distribution protective devices and equipment include, but are not limited to, substation breakers, fuse cutouts, and line reclosers. ~~This screen does not apply to level 1 applications.~~

(f) The initial review screen determines the type of interconnection to a primary distribution line for the proposed DER, according to the requirements specified in the table in this subdivision. This screen includes a review of the type of electrical service provided to the applicant, including line configuration and the transformer connection to limit the potential for creating over-voltages on the electric utility's distribution system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result
3-phase, 3 wire	3-phase or single phase, phase-to-phase	Pass screen
3-phase, 4 wire	Effectively-grounded 3- phase or single-phase, line-to-neutral	Pass screen

(g) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed DER export capacity, may not exceed 20 kWac or 65% of the transformer nameplate rating.

(h) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the 2 sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

(i) If the proposed DER is single-phase and is to be interconnected to a 3-phase service, its nameplate rating may not exceed 10% of the service transformer nameplate rating.

(j) If the proposed DER's point of common coupling is behind a line voltage regulator, the DER's nameplate rating must be less than 250 kWac. This screen does not include substation voltage regulators.

Commented [A8]: The Company does not have remote access to daytime loadings at all of the substations and line reclosers, and it could be some time before that capability is realized at all devices. Where DSCADA is not available, Consumers Energy would have regulator peak reads and real-time reads while physically at the substation, but no ability to develop a load profile. Site visits would be required to obtain those regulator reads. The Company recommends this requirement be removed from the interconnection rules.

Commented [A9]: Remote access to daytime loadings is not available on all line sections and may not be available for some time. The Company recommends that utilities should only be required to consider using applicable loading as the data becomes available as part of normal business practices.

Commented [A10]: The exclusion of Levels 1 and 2 non-export DER removes the ability for utilities to screen for safety and reliability issues. Level 1 and 2 non-export projects can increase the risk of anti-islanding of existing DER and therefore should not be excluded from the screen. The Company recommends Level 1 and 2 non-export DER's be included in screens.

Commented [A11]: Evaluating the risk of islanding using applicable loading (e.g. daytime for solar) and unmasking load is meant to be evaluated in the supplemental review R 460.950 (5)(a) due to increased cost and time requirements.

Commented [A12]: The exclusion of Level 1 removes the ability for utilities to screen for safety and reliability issues. The Company recommends this language be removed from 460.946 (4)(d).

Commented [A13]: The exclusion of Level 1 removes the ability for utilities to screen for safety and reliability issues. The Company recommends this language be removed from 460.946 (4)(e).

(5) If the proposed interconnection passes the initial review screens, or if the proposed interconnection fails the screens but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant. If a facilities study is not required, the interconnection application must proceed under R 460.964 to an interconnection agreement. If a facilities study is required, the interconnection application must proceed under R 460.962.

(6) If the proposed interconnection fails any of the initial review screens, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the initial review screens, and offer all of the following options:

(a) Attend a customer options meeting, as described in R 460.948.

(b) Proceed to supplemental review under R 460.950.

(c) Submit within 60 business days from the date of the electric utility notification, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility. The application modifications must mitigate or eliminate the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility determines the application is accepted, the revised interconnection application must proceed under subrule (3) of this rule.

(d) Withdraw the interconnection application.

(7) If the applicant does not select a course of action under subrule (6) of this rule within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.948 Fast track; customer options meeting.

Rule 48. (1) Upon an applicant’s request, the electric utility and the applicant shall schedule a customer options meeting between the electric utility and the applicant to review possible facility modifications, screen analysis, and related results to determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The customer options meeting must take place within 30 business days of the date of notification pursuant to R 460.946(6).

(2) At the customer options meeting, the electric utility shall offer all of the following options:

(a) Proceed to a supplemental review pursuant to R 460.950.

(b) Continue evaluating the interconnection application under the study track pursuant to R 460.952.

(c) Submit within 60 business days from the date of the customer options meeting, with up to 2 submissions during this time period, a complete and conforming revised interconnection application that includes application modifications offered or required by the electric utility, which mitigates or eliminates the factors that caused the interconnection application to fail 1 or more of the initial review screens. After each submission of information, the electric utility has 10 business days to notify the applicant that the interconnection application is either accepted or rejected due to continuing deficiencies. If the applicant does not meet the timelines required by this subrule, the electric utility may withdraw the application. After the electric utility accepts the revised interconnection application, it must proceed under R 460.946(3).

(d) Withdraw the interconnection application.

(3) Following the customer options meeting, the applicant has up to 20 business days to decide on a course of action and notify the electric utility. In the absence of this notification within the required time, the electric utility shall withdraw the application.

(4) The customer options meeting may take place in person or via telecommunications.

R 460.950 Fast track; supplemental review.

Rule 50. (1) An electric utility shall list in its interconnection procedures the supplemental review screens specified in subrule (5) of this rule. An electric utility may add additional details to each of these screens in the interconnection procedures.

(x) An electric utility may include additional supplemental review screens in its interconnection procedures. In its application requesting approval of interconnection procedures, the electric utility shall provide a detailed technical rationale for the inclusion of each supplemental review screen. If an additional screen negates or undermines any of the supplemental review screens specified in subrule (5) of this rule, the rationale must include an explanation of the technical justification for the additional screen.

(2) An electric utility may waive application of 1, some, or all of the supplemental review screens.

(3) To receive a supplemental review, an applicant shall submit payment of the supplemental review fee within 20 business days of agreeing to a supplemental review. If payment of the fee has not been received by the electric utility within 25 business days, the electric utility shall withdraw the interconnection application.

(4) Within 30 business days after the applicant pays the applicable supplemental review fee or fees, an electric utility shall perform a supplemental review and notify the applicant of the results. The supplemental review must consist of applying the initial review screens selected by the electric utility pursuant to subrule (2) of this rule to the proposed DER. The electric utility shall not require a system impact study if the DER passes the applied supplemental review screens.

(5) The supplemental review screens must include all of the following:

(a) Minimum load screen. Where 12 months of line section minimum load data, including onsite load but not station service load served by the proposed DER, are available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the aggregate DER capacity on the line section must be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data are not available, or cannot be calculated, estimated, or determined, an electric utility shall include the reason or reasons that it is unable to calculate, estimate, or determine minimum load in its supplemental review results notification under subrules (6) and (7) of this rule. All of the following must be applied by the electric utility:

Commented [A14]: The Company recommends this previously deleted language that allows utilities to include additional screens in its interconnection procedures be reinstated.

(i) The type of generation used by the proposed DER will be considered when calculating, estimating, or determining circuit or line section minimum load relevant for the application of the minimum load screen specified in subrule (5)(a) of this rule. Solar photovoltaic generation systems with no battery storage must use daytime minimum load. All other generation must use absolute minimum load unless an operating schedule is provided.

(ii) When this screen is being applied to a DER that serves some station service load, only the net injection of electric energy into the electric utility's distribution system may be considered as part of the aggregate generation.

(iii) The electric utility shall not consider as part of the aggregate generation, for purposes of this supplemental screen, DER capacity known to be already reflected in the minimum load data.

(b) Voltage and power quality screen. In aggregate with existing generation on the line section, all of the following conditions must be met:

(i) The voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions.

(ii) The voltage fluctuation is within acceptable limits as defined by the IEEE Standard 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

(c) Safety and reliability screen. The location of the proposed DER and the aggregate generation capacity on the line section may not create impacts to safety or reliability that require application of the study track to address. An electric utility shall consider all of the following when determining potential impacts to safety and reliability in applying this screen:

(i) Whether the line section has significant minimum loading levels dominated by a small number of customers, such as several large commercial customers.

(ii) Whether the loading along the line section is uniform.

(iii) Whether the proposed DER is located less than 0.5 electrical circuit miles for less than 5 kV or less than 2.5 electrical circuit miles for greater than 5 kV from the substation. In addition, whether the line section from the substation to the point of common coupling is a mainline rated for normal and emergency ampacity.

(iv) Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the distribution system until distribution system voltage and frequency are within normal limits for a prescribed time.

(v) Whether operational flexibility is reduced by the proposed DER, such that transfer of the line section or sections of the DER to a neighboring distribution circuit or substation may trigger overloads, power quality issues, or voltage issues.

(vi) Whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues including, but not limited to, islanding, reverse power flow, or voltage quality.

(6) If the proposed interconnection passes the supplemental review, or if the proposed interconnection fails the review but the electric utility determines that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant and the interconnection application must proceed pursuant to both of the following:

(a) If the proposed interconnection requires a facilities study, the interconnection application must proceed under R 460.962.

(b) If the proposed interconnection does not require further study, the interconnection application must proceed under R 460.964 to an interconnection agreement.

(7) If the proposed interconnection fails any of the supplemental review screens or the electrical utility is unable to perform a supplemental review screen, and the electric utility does not or cannot determine that the DER may be interconnected consistent with safety, reliability, and power quality standards, the electric utility shall notify the applicant, provide the applicant with the results of the application of the supplemental review screens, and offer both of the following options:

(a) Stop the supplemental review and continue evaluating the proposed interconnection under the study track under R 460.952.

(b) Withdraw the interconnection application.

(8) For subrules (6) and (7) of this rule, if an applicant does not select a course of action within 10 business days of notice from the electric utility, the electric utility shall withdraw the interconnection application.

R 460.952 Study track.

Rule 52. (1) An electric utility shall use the study track to evaluate an interconnection application that has been accepted under R 460.936 if 1 or more of the following conditions is met:

(a) The DER is not eligible for the non-export track or fast track.

(b) The DER did not pass the initial review screens as part of the fast track and the applicant selected the study track option in the customer options meeting.

(c) The DER did not pass 1 or more supplemental review screens.

(d) The DER was evaluated under the non-export track and further study is required.

(e) The DER is eligible for the fast track, but the applicant elected the study track.

(2) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(a) of this rule, within 10 business days after the electric utility notifies the applicant that the interconnection application has been accepted pursuant to R 460.936, the electric utility shall provide to the applicant an individual study agreement or an agreement for an alternative process pursuant to R 460.956.

(3) If the interconnection application must be evaluated under the study track because it meets the criteria of subrule (1)(b), (c), or (d), of this rule, within 10 business days after the applicant has notified the electric utility to proceed to the study track, the electric utility shall provide to the applicant an individual study agreement or an agreement for an alternative process.

(4) An electric utility's interconnection procedures may include a provision for determining appropriate milestone payments to include with the system impact study fee and facilities study fee.

R 460.954 Individual study.

Rule 54. (1) An electric utility that is evaluating DERs in the study track individually shall process the interconnection applications in the order in which the applications were placed into the study track, taking into account withdrawn interconnection applications and electrically remote DERs.

(a) An electrically remote DER in an individual study may be studied on an expedited schedule relative to electrically coincident DERs. Electrically remote DERs must be studied in the order the interconnection applications were considered complete.

(2) When an interconnection application is delayed due to an affected system issue, informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or a complaint pursuant to R 792.10439 to R 792.10446, other interconnection applications that were placed into the study track on a later date may progress in the order in which the interconnection applications were placed into the study track.

(3) An individual study process must consist of a system impact study pursuant to R 460.960 and a facilities study pursuant to R 460.962. An electric utility may waive 1 or both studies for a particular interconnection application. An electric utility may specify additional studies it may perform on an interconnection application in its interconnection procedures, provided the electric utility is able to meet all applicable timelines associated with an individual study process.

(4) Interconnection applications that meet all of the following requirements must be admitted into an individual study:

(a) An electric utility determined the application to be complete and conforming.

(b) An application qualifies for study track pursuant to R 460.952.

(c) An interconnection application has a pre-application report, when required by R 460.936(2).

(d) An applicant has paid all required fees.

(e) An applicant has signed and returned an individual study agreement.

R 460.956 Alternative process.

Rule 56. An electric utility may use a process to study interconnection applications that is different from the process described by R 460.954 and R 460.958 to R 460.962. If an electric utility elects to use an alternative process, this process must be described in the electric utility's interconnection procedures.

R 460.958 Scoping meeting for interconnection applications that are to be studied individually.

Rule 58. (1) This rule applies only to interconnection applications proceeding pursuant an individual study agreement.

(2) Upon request of the applicant, the electric utility and the applicant shall schedule a scoping meeting between the electric utility and the applicant to discuss the interconnection application and review existing fast track results, if any. The scoping meeting must take place within 20 business days after the interconnection application is considered complete by the electric utility or, if applicable, the fast track has been completed and the applicant has elected to continue with the system impact study or facilities study.

(3) Scoping meetings are limited to 1 hour per application. Multiple applications by the same applicant may be addressed in the same meeting.
(4) The scoping meeting may occur in-person or via telecommunications.
(5) During the scoping meeting, the electric utility shall identify and communicate to the applicant whether the applicant must proceed to a system impact study, a facilities study, or an interconnection agreement and the basis for that decision, and 1 of the following must occur:
(a) If a system impact study must be performed, the interconnection application proceeds to R 460.960.
(b) If a facilities study must be performed, the interconnection application proceeds to R 460.962.
(c) If a system impact study is not required and a facilities study is not required, the interconnection application must proceed to R 460.964 for an interconnection agreement.

R 460.960 System impact study agreement, scope, procedure, and review meeting.
Rule 60. (1) For all DERs being studied individually, all of the following apply:
(a) An electric utility shall provide the applicant a system impact study agreement within 5 business days of proceeding to this rule.
(b) A system impact study agreement must include all of the following:
(i) An outline of the scope of the study.
(ii) The applicable fee including appropriate credit for any studies previously completed pursuant to the fast track or non-export track.
(iii) If necessary, a list of any additional and reasonable technical data needed from the applicant to perform the system impact study.
(iv) A timeline for completion of the system impact study.
(v) A list of the information that must be provided to the applicant in the system impact study report.
(c) An applicant who has requested a system impact study shall return the completed system impact study agreement, provide any additional technical data requested by the electric utility, and pay the required fee within 20 business days. An electric utility may consider the application withdrawn if the system impact study agreement, payment, and required technical data are not returned within 20 business days.
(d) A system impact study must identify and describe the electric system impacts that would result if the proposed DER was interconnected without electric system modifications. A system impact study must provide a non-binding good faith list of facilities that are required as a result of the application and non-binding estimates of costs and time to construct these facilities.
(e) An electric utility shall explain in its interconnection procedures the process for conducting system impact studies on DERs when there is an affected system issue.
(f) The electric utility shall complete the system impact study and transmit a system impact study report to the applicant within 60 business days of the receipt of the signed system impact study agreement, payment of the system impact study fee, and any necessary technical data. If necessary, the electric utility shall transmit a facilities study agreement to the applicant within 60 business days of receipt of the signed system impact study agreement, payment of all applicable fees, and any necessary technical data.

(g) An electric utility may request reasonable additional data from the applicant within 20 business days of beginning the system impact study. The electric utility and the applicant shall work together to resolve the additional data request so that the electric utility will be able to complete the system impact study within 60 business days as specified in subrule (1)(f) of this rule.

(h) Within 15 business days of receiving the system impact study report, the applicant shall notify the electric utility that it plans to pursue a system impact study review meeting, proceed to a facilities study pursuant to R 460.962, or withdraw the application. If the applicant fails to notify the electric utility within 15 business days, the electric utility may consider the application to be withdrawn.

(i) Upon request by the applicant pursuant to subrule (1)(h) of this rule, the electric utility and the applicant shall schedule a system impact study review meeting between the electric utility and the applicant to review system impact study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The system impact study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant plans to attend a system impact study review meeting.

(j) At the system impact study review meeting, the electric utility shall offer the applicant the option to withdraw the interconnection application, and 1 of the following options:

(i) Proceed to a facilities study pursuant to R 460.962.

(ii) Proceed directly to R 460.964 for an interconnection agreement.

(k) Following the meeting, the applicant has not more than 45 business days to decide on a course of action. If an applicant fails to notify the electric utility within 45 business days, the electric utility may consider the application to be withdrawn.

(l) The system impact study review meeting may occur in-person or via telecommunications.

R 460.962 Facilities study agreement, scope, procedure; review meeting.

Rule 62. (1) For DERs being studied individually, all of the following apply:

(a) If construction of facilities is required to provide interconnection and interoperability of the DER with the electric utility's distribution system, the electric utility shall provide the applicant a facilities study agreement and the results of the applicant's system impact study pursuant to R 460.960, if applicable. If no system impact study was performed, the electric utility shall provide a facilities study agreement within 10 business days of proceeding to this rule.

(b) The facilities study agreement must include the following:

(i) An outline of the scope of the study.

(ii) The applicable fee including appropriate credit for any studies previously completed pursuant to the fast track or non-export track.

(iii) A timeline for completion of the facilities study.

(iv) A list of the information that will be provided to the applicant in the facilities study report.

(c) The applicant shall return the signed facilities study agreement and pay the required facilities study fee within 20 business days. The electric utility may withdraw the application if the facilities study agreement and payment are not returned within 20 business days.

(d) A facilities study must specify and estimate the cost of the required equipment, engineering, procurement, and construction work, including overheads, needed to interconnect the DER, and an estimated timeline for the completion of construction. The electric utility shall provide cost estimates that are detailed and itemized.

(e) The electric utility shall explain in its interconnection procedures the process for conducting facilities studies on DERs while there is an affected system issue.

(f) The electric utility shall complete the facilities study and transmit a facilities study report to the applicant within 80 business days of the receipt of the signed facilities study agreement and payment of the facilities study fee.

(g) Within 10 business days of receiving a facilities study report from the electric utility, the applicant shall select 1 option from the following options:

(i) Request a facilities study review meeting with the electric utility.

(ii) Proceed to an interconnection agreement pursuant to R 460.964.

(iii) Withdraw the interconnection application.

If the applicant fails to inform the electric utility within 10 business days of its chosen course of action, the electric utility may consider the application withdrawn.

(h) Upon request by the applicant pursuant to subrule (1)(g)(i) of this rule, the electric utility and the applicant shall schedule a facilities study review to review the facilities study results and determine what further steps are needed to permit the DER to be connected safely and reliably to the distribution system. The facilities study review meeting must take place within 25 business days of the electric utility receiving notification that the applicant will attend a facilities study review meeting.

(i) At the facilities study review meeting, the electric utility shall offer both of the following options:

(i) Proceed to an interconnection agreement pursuant to R 460.964.

(ii) Withdraw the interconnection application.

(j) Following the meeting, the applicant has no more than 20 business days to decide on a course of action and notify the electric utility of this course of action. If the applicant fails to notify the electric utility within 20 business days, the electric utility may withdraw the application.

(k) The facilities study review meeting may be conducted in-person or via telecommunications.

R 460.964 Interconnection agreement.

Rule 64. (1) For level 1, 2, or 3 interconnection applications, where no construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement, which may include modifications to address any special operating conditions, to an applicant within 3 business days of reaching this stage.

(2) For level 1, 2, or 3 interconnection applications, where construction of interconnection facilities or distribution upgrades is required, an electric utility shall provide its standard level 1, 2, and 3 interconnection agreement with modifications to address any special operating conditions, required construction activities, construction

milestone timing, and cost to an applicant within 5 business days of reaching this stage. The applicant and electric utility shall mutually agree on the timing of construction milestones.

(3) For an applicant with level 1, 2, or 3 interconnection applications, the applicant shall sign and return the standard level 1, 2, and 3 interconnection agreement with payment, if applicable, within 20 business days of receiving the agreement.

(a) If the applicant did not sign and return the standard level 1, 2, and 3 interconnection agreement and payment, if applicable, within 20 business days, the electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility did not receive the signed standard level 1, 2, and 3 interconnection agreement and any applicable payment during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn subject to subrule 3(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, the formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within the 20 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and any applicable payment.

(4) For level 1, 2, or 3 projects, the electric utility shall countersign and provide a completed copy of the standard level 1, 2, and 3 interconnection agreement within 10 business days of the applicant returning the signed standard level 1, 2, and 3 interconnection agreement and the interconnection application shall proceed to R 460.966.

(5) For level 4 or 5 projects, the electric utility shall provide its level 4 and 5 interconnection agreement, which may include modifications to address any special operating conditions, within 10 business days of reaching this stage. When construction of interconnection facilities or distribution upgrades is necessary, the level 4 and 5 interconnection agreement must contain either timelines for completion of activities and estimates of construction costs or a timetable when these requirements can be determined. The interconnection agreement must include a payment schedule that corresponds to the milestones established and must require the electric utility to refund any unspent and unobligated funds if the agreement is terminated.

(6) For an applicant with level 4 or 5 DERs, the applicant shall sign and return with payment, if applicable, a level 4 and 5 interconnection agreement within 30 business days.

(a) If the applicant does not sign and return the level 4 and 5 interconnection agreement with payment within 30 business days, an electric utility shall notify the applicant of the missed deadline and grant an extension of 15 business days. If the electric utility does not receive the signed level 4 and 5 interconnection agreement and payment, if applicable, during the 15-business-day extension, the electric utility may consider the interconnection application withdrawn, subject to subrule (6)(b) of this rule.

(b) If the applicant begins either the informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 within 30 business days, the outcome of that process must establish a time frame for the applicant to return the signed interconnection agreement and applicable payment. There is a rebuttable presumption in the complaint proceeding that the electric utility's standard construction, procurement, installation, design, and cost practices are lawful, reasonable, and prudent.

(i) For study track interconnection applications filed with an electric utility conducting individual studies, electrically coincident applications filed after the interconnection application must be placed on hold for not more than 60 business days. If either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446 does not result in the applicant returning a signed interconnection agreement with any applicable payment within 60 business days and there are electrically coincident interconnection applications in progress behind this application, the electric utility may require the withdrawal of the interconnection application.

(7) For level 4 or 5 projects, an electric utility shall countersign and provide a completed copy of the level 4 and 5 interconnection agreement within 10 business days of the applicant returning a mutually agreed-upon and signed level 4 and 5 interconnection agreement and the interconnection application shall proceed to R 460.966.

(8) An applicant shall pay the actual cost of the interconnection facilities and distribution upgrades. The cost to the applicant for interconnection facilities and distribution upgrades may not exceed 110% of the estimate without an itemized summary and explanation of cost increases being provided to the applicant.If the costs are expected to exceed 125% of the estimate, the electric utility shall provide further explanation to the applicant prior to the costs being incurred. If the applicant does not consent in writing to pay the additional costs within 20 business days of receiving further explanation from the electric utility, the electric utility shall initiate informal mediation pursuant to R 460.904 no later than 5 business days after the conclusion of the 20 business day applicant consent period. The applicant may dispute the expected costs pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute.

(9) A party's obligations under the interconnection agreement may be extended by agreement. If a party anticipates that it will be unable to meet a milestone for any reason other than an unforeseen event, the party shall do all of the following:

(a) Immediately notify the other party of the reason or reasons for not meeting the milestone.

(b) Propose the earliest alternate date when it can attain this and future milestones.

(c) Request amendments to the interconnection agreement, if needed to address the changed milestones.

(10) The party affected by the failure to meet a milestone shall not withhold agreement to any amendments proposed in subrule (9)(c) of this rule unless 1 of the following applies:

(a) The party affected will suffer significant uncompensated economic or operational harm from the amendment or amendments.

(b) The milestone under question has been previously delayed. (c) The affected party has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the party proposing the amendment.

(11) If the party affected by the failure to meet a milestone disputes the proposed extension, the affected party may pursue either informal mediation pursuant to R

460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446.

(12) The electric utility shall provide the applicant with a final accounting report of any difference between costs charged to the applicant and previous payments to the electric utility for interconnection facilities or distribution upgrades.

(a) If the costs charged to the applicant exceed its previous aggregate payments, the electric utility shall bill the applicant for the amount due and the applicant shall make a payment to the electric utility within 20 business days of the final accounting report. The applicant may dispute the invoice pursuant to either informal mediation pursuant to R 460.904, formal mediation pursuant to R 460.906, or the complaint process pursuant to R 792.10439 to R 792.10446. If there is a dispute, the applicant shall make payment within 30 business days of final resolution of the dispute. Failure by the applicant to pay its costs is cause for disconnection of the applicant's DER.

(b) If the applicant's previous aggregate payments exceed its costs under the interconnection agreement, the electric utility shall refund to the applicant an amount equal to the difference within 20 business days of the final accounting report.

(13) The electric utility is responsible for specifying requirements in interconnection agreements to support independent system operator regulations or regional transmission operator regulations.

(14) The electric utility may propose to the commission that a signed interconnection agreement be modified to require compliance with changes to an independent system operator, a regional transmission operator, or the state's regulations, provided that these modifications do not alter the rights or obligations of the interconnection customer. Unless the electric utility has the consent of the applicant or interconnection customer in writing, an electric utility shall not modify a signed interconnection agreement without commission approval.

R 460.966 Inspection, testing, and commissioning.

Rule 66. (1) If the interconnection application requires telecommunications, cybersecurity, data exchange or remote controls operation, successful testing and certification of these items must be completed prior to or during testing. The electric utility's interconnection procedures must describe the technical requirements of common items, but site-specific requirements may be included in the interconnection agreement.

(2) An applicant shall notify the electric utility when installation of a DER and any required local code inspection and approval is complete. The applicant shall provide any test reports or configuration documents as defined in the standard level 1, 2, and 3 interconnection agreement or level 4 and 5 interconnection agreement.

(3) The electric utility shall review the applicant's inspection, test reports, or configuration documents, and communicate its intent to perform a witness or commissioning test, or waive its right to perform a witness test and commissioning test within 10 business days. If the electric utility finds the applicant's inspection, test reports, or configuration documents to be incomplete, insufficient, or unsatisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant shall have at least 20 business days to implement corrections to those documents. The applicant, after taking corrective action,

shall request the electric utility to reconsider its inspection, test reports, or configuration documents.

(4) If the electric utility intends to witness or perform commissioning tests required to comply with the interconnection agreement or the interconnection procedures and inspect the DER, the electric utility shall witness or perform the commissioning tests and inspect the DER within the following:

(a) Ten business days of receiving the notification from the applicant pursuant to subrule (2) of this rule for level 1 applications.

(b) Twenty business days of receiving the notification from the applicant pursuant to subrule (2) of this rule for level 2 and level 3 applications.

(c) A mutually-agreed upon timeframe after receiving the notification from the applicant pursuant to subrule (2) of this rule for level 4 and 5 applications.

(5) The electric utility may waive its right to visit the site and inspect the DER or perform the commissioning tests.

(a) If the electric utility waives this right, it shall provide a written waiver to the applicant within 10 business days from receiving the notification from the applicant pursuant to subrule (2) of this rule.

(b) The applicant shall provide the electric utility with the completed commissioning test report within 20 business days of receipt of the electric utility's written waiver.

(6) If the electric utility attempts to conduct the inspection and testing pursuant to subrule (4) of this rule at the arranged time and is unable to access the DER or complete the testing, the DER must remain disconnected until the applicant and the electric utility can complete the inspection and testing.

(7) If the electric utility witnessed or performed commissioning tests and inspected the DER pursuant to subrule (4) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report and found the site to be satisfactory or unsatisfactory.

(a) If the commissioning test report is accepted and the site was found satisfactory, the electric utility shall provide the notification of acceptance in writing, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report or did not find the site satisfactory, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, shall request the electric utility to reconsider its findings. The applicant may be billed the actual cost of any re-inspections.

(8) If the electric utility waived its right to witness or perform commissioning tests and inspect the DER pursuant to subrule (5) of this rule, within 5 business days of the receipt of the completed commissioning test report, the electric utility shall notify the applicant whether it has accepted or rejected the commissioning test report.

(a) If the commissioning test report is accepted, the electric utility shall provide notification of acceptance, and the interconnection application proceeds to R 460.968.

(b) If the electric utility rejects the commissioning test report, the electric utility shall provide its reasons for doing so in writing and the applicant has not less than 20 business days to implement corrections. The applicant, after taking corrective action, may then request the electric utility to reconsider its findings.

(9) The cost of testing and inspection for applicants participating in an electric utility's distributed generation program, as described in part 3 of these rules, R 460.1001 to R 460.1026, are considered a cost of operating a distributed generation program and must be recovered pursuant to section 175(1) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1175.

(10) If the applicant does not notify the electric utility that the DER is installed and ready to test pursuant to subrule (2) of this rule, the electric utility may, in writing, query the status of the interconnection. If the applicant does not provide a written response within 10 business days or no progress is evident, the electric utility may consider the interconnection application withdrawn.

R 460.968 Authorization required prior to parallel operation.

Rule 68. (1) The electric utility shall provide to the applicant written authorization to operate in parallel with the electric utility within 5 business days of all of the following conditions being met:

(a) The electric utility notified the interconnection applicant that the commissioning test and inspection, where applicable, are accepted.

(b) The applicant complied with all applicable parallel operation requirements as set forth in the electric utility's interconnection procedures and applicable interconnection agreement.

(c) The applicant complied with all applicable local, state, and federal requirements.

(d) The electric utility received full payments for all outstanding bills.

(2) With the written authorization, interconnection of the DER is considered approved for parallel operation, the DER may begin operating, and the applicant is considered an interconnection customer.

(3) The applicant shall not operate its DER in parallel with the electric utility's distribution system without prior written permission to operate from the electric utility.

(4) Subject to reasonable timing and other conditions, including completion of conditions in the interconnection agreement or interconnection procedures, the electric utility shall allow for reasonable but limited testing before written authorization has occurred.

R 460.970 Cost allocation of interconnection facilities, distribution upgrades, and associated operation and maintenance costs.

Rule 70. Costs for interconnection facilities, distribution upgrades, and associated operation and maintenance costs must be classified into 1 of the following categories:

(a) Site-specific costs, which include, but are not limited to, costs of interconnection facilities and distribution upgrades that are caused by 1 DER, whether that DER is electrically co-incident with other DERs or not. These costs must be assigned to the cost-causing applicant.

(b) Shared interconnection facilities costs, which are costs caused by DERs which together necessitate the construction of interconnection facilities. The interconnection facilities costs, including any associated operation and maintenance costs, that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

(c) Shared distribution upgrade costs, which are costs caused by electrically co-incident DERs that together necessitate a distribution upgrade. The distribution upgrade costs, including any associated operation and maintenance costs, that should be shared must be allocated to each applicant based on a methodology described in the electric utility's interconnection procedures.

R 460.974 Interconnection metering and communications.

Rule 74. (1) Any metering and communications requirements necessitated by use of the DER must be installed at the applicant's expense. The electric utility may furnish this equipment at the applicant's expense.

(2) The electric utility may charge the interconnection customer reasonable ongoing fees to maintain the metering and communications equipment. These fees must be listed in the interconnection agreement.

R 460.976 Post commissioning remedy.

Rule 76. (1) If the electric utility finds that the DER is operating outside the terms of the interconnection agreement but does not find immediate disconnection pursuant to R 460.978(1)(f) and (g) warranted, the electric utility shall promptly inform the interconnection customer or its agent of this finding. The interconnection customer is responsible for bringing the DER into compliance within 30 business days or a mutually agreed-upon time period. The electric utility may perform an inspection of the DER after a remedy is applied.

(2) If the DER is not brought into compliance within 30 business days or the mutually agreed-upon time period, the electric utility may apply a remedy and bill the interconnection customer. The interconnection customer shall pay this bill within 5 business days.

R 460.978 Disconnection.

Rule 78. (1) An electric utility may refuse to connect or may disconnect a project from the distribution system if any of the following conditions apply:

(a) Failure of the interconnection customer to bring a DER into compliance pursuant to R 460.976(1).

(b) Failure of the interconnection customer to pay costs of remedy pursuant to R 460.976(2).

(c) Termination of interconnection by mutual agreement.

(d) Distribution system emergency, but only for the time necessary to resolve the emergency.

(e) Routine maintenance, repairs, and modifications performed in a reasonable time and with prior notice to the interconnection customer.

(f) Noncompliance with technical or contractual requirements in the interconnection agreement that could lead to degradation of distribution system reliability, electric utility equipment, and electric customers' equipment.
(g) Noncompliance with technical or contractual requirements in the interconnection agreement that presents a safety hazard.
(h) Other material noncompliance with the interconnection agreement.
(i) Operating in parallel without prior written authorization from the electric utility as provided for in R 460.968.
(2) An electric utility may disconnect electric service, where applicable, pursuant to R 460.136.

R 460.980 Capacity of the DER.
Rule 80. (1) If the interconnection application requests an increase in capacity for an existing DER, the electric utility shall evaluate the application based on the ~~new ongoing operating capacity~~ nameplate capacity of the DER. The maximum capacity of a DER is the aggregate nameplate capacity or may be limited as described in the electric utility's interconnection procedures.
(2) An interconnection application for a DER that includes single or multiple types of DERs at a site for which the applicant seeks a single point of common coupling must be evaluated as described in the electric utility's interconnection procedures.
(3) The electric utility's interconnection procedures must include acceptable methods for power limited export DER so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported.
(4) An electric utility shall allow interconnection of limited-export or non-exporting DERs according to this subrule. If a DER uses any configuration or operating mode in this subrule to limit the export of electrical power across the point of common coupling, then the generating capacity shall be only the amount capable of being exported not including any inadvertent export. To prevent impacts on system safety and reliability, any inadvertent export from a DER must comply with the limits in subdivisions (e) or (f) of this subrule. The generating capacity specified by the applicant in the application will subsequently be included as a limitation in the interconnection agreement. Other means not listed in this subrule may be utilized to limit export if mutually agreed upon by the electric utility and applicant.
(a) To ~~ensure~~ stop power ~~is~~ from being ~~never~~ exported across the point of common coupling, a reverse power protective function may be provided. ~~The default setting for this protective function shall be 0.1% export of the service transformer's rating, with a maximum 2.0 second time delay.~~
(b)To ~~ensure~~ stop power from being exported ~~at least a minimum amount of power is imported~~ across the point of common coupling ~~at all times and, therefore, that power is not exported~~, an under-power protective function may be provided. ~~The default setting for this protective function shall be 5% import of the DER's total nameplate rating, with a maximum 2.0 second time delay.~~
~~(c)This option requires the nameplate rating of the DER, minus any auxiliary load, to be so small in comparison to its host facility's minimum load that the use of additional~~

Commented [A15]: As reflected in CE's comments, the Company's preferred revision to this section is that all of Section R 460.980 be revised to mirror the R 460.980 section included in the September 9, 2021 order in Case No. U-20890 Exhibit B.

Commented [A16]: The Company also recommends relocating subrule (1) and (2) to sections related to material modification and applications.

Commented [A17]: Reverse power (non-exporting) protective functions don't ensure power is never exported. The protection is meant to detect and remove export above a set value.

There are projects that use reverse power protection at locations where there is no service transformer. For this reason, if 460.980 (4)(a) is not deleted, the Company recommends the setting criteria be defined in the utility procedures.

Commented [A18]: Under-power (non-exporting) protective functions don't ensure power is never exported. Under-power protection is meant to detect and remove export.

For this reason, if 460.980 (4)(b) is not deleted, the Company recommends the setting criteria be defined in the utility procedures.

~~protective functions is not required to ensure that power will not be exported to the distribution system. This option requires the DER capacity to be no greater than 50% of the applicant's verifiable minimum host load over the past 12 months.~~

(d) A certified power control system that ~~reduced output rating utilizing the power rating configuration setting may be used to~~ ensures the DER does not generate power beyond a certain value lower than the nameplate rating.

(e) ~~DERs may utilize, a nationally recognized testing laboratory~~A certified power control system ~~and inverter system~~ that results in the DER ~~disconnecting from the distribution system, ceasing to energize the distribution system or halting energy production~~limiting inadvertent export ~~within 2 seconds if the period of continuous inadvertent export exceeds 30 seconds~~. The electric utility may require additional protective functions. ~~Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER entering an operational mode where no energy is exported across the point of common coupling to the distribution system.~~

(f) DERs may be designed with other control systems or protective functions, or both that are mutually agreed upon by the applicant and the electric utility, to limit export and inadvertent export to levels mutually agreed upon by the applicant and the electric utility. The limits may be based on technical limitations of the applicant's equipment or the distribution system's equipment. To ensure inadvertent export remains within mutually agreed-upon limits, the applicant shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

R 460.982 Modification of the interconnection application.

Rule 82. (1) At any point after an interconnection application is considered accepted but before the signing of an interconnection agreement, the applicant, the electric utility, or the affected system owner may propose modifications to the interconnection application that may improve the costs and benefits of the interconnection, or that improve the ability of the electric utility to accommodate the interconnection. The applicant shall submit to the electric utility, in writing, all proposed modifications to any information provided in the interconnection application and the electric utility shall perform an evaluation to determine whether the proposed modification is a material modification and provide the results to the applicant within 10 business days.

(2) The electric utility shall not be required to accept or implement a modification to the electric utility's distribution system or generation assets that is proposed by an applicant or affected system operator.

(3) The applicant may request a 1-hour consultation to discuss the results of the material modification review.

(4) Neither the electric utility nor the affected system operator may unilaterally modify an accepted interconnection application. If the electric utility evaluates DERs using individual studies, the timelines specific to that interconnection application must be placed on hold while the proposed modification is being evaluated by the electric utility.

(5) For a proposed modification which the electric utility has determined is a material modification and that further study is required, the applicant shall select 1 of the following options:

Commented [A19]: If 460.980 (4)(c) is not deleted, the Company recommends it be updated to include references to the specific protection functions being referred to in R 460.980 (a) and (b). The current language can be misinterpreted as meaning that additional protection functions defined in the utility procedures (e.g. 51V, 59N) are not required.

Commented [A20]: The Company believes this requirement is a safety and reliability concern. Utilities cannot study the impact of a DER assuming the current (or future) owner will maintain the minimum load for the lifespan of the DER. Failure of an applicant or future DER owner to maintain minimum load may lead to damaged equipment. For this reason, the Company recommends 460.980 (4)(c) should be removed.

Commented [A21]: A power rating configuration setting is a power control system. A power rating configuration setting needs to be certified. If 460.980 (4) (d) is not deleted, the Company recommends replacing "power rating configuration settings" with "power control system". The power control system definition includes the certification requirements.

Commented [A22]: If 460.980 (4)(e) is not deleted, the Company notes that a certified power control system includes inverter systems, and recommends that specifically calling them out is not required. This comment also applies to "or inverter system" in the same paragraph below.

Commented [A23]: The UL 1741 CRD for PCS testing standard states that the open loop response time will be 30 seconds by default but also notes that faster PCS response times may be required to meet specific utility requirements. If 460.980 (4)(e) is not deleted, the Company recommends that the slowest response time, in order for certification, should be defined in utility procedures.

Commented [A24]: The UL 1741 CRD for PCS testing standard does not provide certification that power control systems disconnect, cease to energize, or halts energy production within any timeframe. The standard is used to certify power control system properly limits the output power and any unscheduled export within a specified timeframe. If 460.980 (4)(e) is not deleted, the Company recommends that the language should be updated to reflect this standard.

Commented [A25]: The Company recommends that non-certified control system or protective functions shall only be accepted if both entities mutually agree. If 460.980 (4)(f) is not deleted, the Company recommends that the requirement for mutual agreement should be added to the rules.

(a) Withdraw the modification.
(b) Withdraw the application.
(c) Propose a different modification to the interconnection application for electric utility review pursuant to subrule (1) of this rule to determine whether the modification is material.
(d) If the electric utility offers an expedited study of the application with the proposed material modification, the applicant may request the expedited study. If the electric utility offers an expedited study, the process of performing an expedited study must be described in the electric utility's interconnection procedures.
(e) Initiate informal mediation pursuant to R 460.904
(f) Initial formal mediation pursuant to R460.906
(g) File a complaint pursuant to R 792.10439 to R 792.10446.

(6) The applicant shall notify the electric utility of its selection pursuant to subrule (5) of this rule within 10 business days of receiving the electric utility notification of the results or the modification may be considered withdrawn.

(7) For a proposed modification which the electric utility has determined is a material modification, but which does not require further study, the electric utility shall continue processing the interconnection application according to these rules.

(8) Any modification to the interconnection application that could affect the operation of the distribution system, including but not limited to, changes to machine data, equipment configuration, or the interconnection site of the DER, not agreed to in writing by the electric utility and the applicant may be treated by the electric utility as a withdrawal of the interconnection application requiring submission of a new interconnection application.

(9) At any point prior to the execution of an interconnection agreement, changes to ownership will cause the interconnection application to be put on hold until the new owner signs all necessary agreements and documents. An electric utility may not be found in violation of these rules related to the processing of the interconnection application during such a transfer of ownership.

(10) The electric utility's interconnection procedures must provide a procedure for performing a material modification review.

R 460.984 Modifications to the DER.

Rule 84. After the execution of the interconnection agreement, the applicant shall notify the electric utility of any plans to modify the DER. The electric utility shall review the proposed modification to determine if the modification is considered a material modification. If the electric utility determines that the modification is a material modification, the electric utility shall notify the applicant, in writing of its determination and the applicant shall submit a new application and application fee along with all supporting materials that are reasonably requested by the electric utility. The applicant may not begin any material modification to the DER until an interconnection agreement incorporating the material modification is fully executed.

R 460.986 Insurance.

Rule 86. (1) An applicant interconnecting a level 1 or 2 project to the distribution system of an electric utility may not be required by the electric utility to obtain any additional liability insurance.

(2) An electric utility shall not require an applicant interconnecting a level 1 or 2 project to name the electric utility as an additional insured party.

(3) For a level 3 project, the applicant shall obtain and maintain general liability insurance of a minimum of $1,000,000.

(4) For a level 4 project, the applicant shall obtain and maintain general liability insurance of a minimum of $2,000,000.

(5) For a level 5 project, the applicant shall obtain and maintain general liability insurance of a minimum of $3,000,000.

(6) For level 3, 4, and 5 projects, the electric utility may describe in its interconnection procedures required terms and conditions which must be specified in the general liability insurance.

R 460.988 Easements and rights-of-way.

Rule 88. If an electric utility line extension is required to accommodate an interconnection, the electric utility is responsible for providing and obtaining easements or rights-of-way. The applicant is responsible for the cost of providing and obtaining easements or rights-of-way.

R 460.990 Interconnection penalties.

Rule 90. Pursuant to section 10e of 1939 PA 3, MCL 460.10e, an electric utility shall take all necessary steps to ensure that DERs are connected to the distribution systems within their operational control. If the commission finds, after notice and hearing, that an electric utility has prevented or unduly delayed the ability of a DER greater than 100 kW to connect to the distribution system of the electric utility, the commission may order remedies designed to make whole the applicant proposing the DER, including, but not limited to, reasonable attorney fees. If the electric utility violates this rule, the commission may order fines of not more than $50,000 per day, commensurate with the demonstrated impact of the violation.

R 460.991 Business day exclusions.

Rule 91. An electric utility shall notify the commission and all applicants that have in-process applications when timelines are being extended due to a day in which electric service is interrupted for 10% or more of an electric utility's customers pursuant to R 460.901a(k). The electric utility shall also notify the commission and all applicants that have in-process applications when application processing resumes.

R 460.992 Electric utility annual reports.

Rule 92. An electric utility shall file an annual interconnection report on a date and in a format determined by the commission.

PART 3. DISTRIBUTED GENERATION PROGRAM STANDARDS

R 460.1001 Application process.

Rule 101. (1) An electric utility shall file initial distributed generation program tariff sheets in the first rate case filed after June 1, 2018.

(2) Within calendar 30 days of a commission order approving an electric utility's initial distributed generation tariff, or within 30 calendar days of the effective date of these rules, whichever is later, an alternative electric supplier serving customers in that electric utility's service territory shall file an updated distributed generation program plan applicable to its customers in the affected electric utility's service territory.

(3) An electric utility and an alternative electric supplier shall annually file a legacy net metering program report and, if applicable, a distributed generation program report not later than March 31 of each year.

(4) An electric utility and an alternative electric supplier shall maintain records of all applications and up-to-date records of all eligible electric generators participating in the legacy net metering program and distribution generation program.

(5) Selection of customers for participation in the legacy net metering program or distributed generation program must be based on the order in which the applications are received.

(6) An electric utility or alternative electric supplier shall not refuse to provide or discontinue electric service to a customer solely because the customer participates in the legacy net metering program or distributed generation program.

(7) The legacy net metering program and distributed generation program provided by electric utilities and alternative electric suppliers must be designed for a period of not less than 10 years and limit each applicant to generation capacity designed to meet up to 100% of the customer's electricity consumption for the previous 12 months.

(a) The generation capacity must be determined by an estimate of the expected annual kWh output of the generator or generators as determined in an electric utility's interconnection procedures and specified on an electric utility's legacy net metering program or distributed generation program tariff sheet or in the alternative electric supplier's legacy net metering program or distributed generation program plan. For projects in which energy export controls are implemented pursuant to section R 460.980 and utilized to limit the export to 100% of the customer's electricity consumption for the previous 12 months, an electric utility shall not add the storage capacity to generation capacity for the purpose of the study. If a customer has multiple inverters capable of exporting to the distribution grid, the inverters must be configured in a way that prevents the cumulative maximum export at any given time to exceed the approved amount in the customer's application.

(b) A customer's electric consumption must be determined by 1 of the following methods:

(i) The customer's annual energy consumption, measured in kWh, during the previous 12-month period.

(ii) If there is no data, incomplete data, or incorrect data for the customer's energy consumption or the customer is making changes on-site that will affect total consumption, the electric utility or alternative electric supplier and the customer shall mutually agree on a method to determine the customer's electric consumption.

(c) A net metering or distributed generation customer using an energy storage device in conjunction with an eligible electric generator shall not design or operate the energy storage device in a manner that results in the customer's electrical output exceeding 100% of the customer's electricity consumption for the previous 12 months. The addition of an energy storage device to an existing approved legacy net metering program system or distributed generation program system is considered a material modification. The electric utility interconnection procedures must include details describing how energy storage equipment may be integrated into an existing legacy net metering program system without impacting the 10-year grandfathering period or participation in the distributed generation program.

(8) An applicant shall notify the electric utility of plans for any material modification to the project. An applicant shall re-apply for interconnection pursuant to part 2 of these rules, R 460.911 to R 460.992, and submit revised legacy net metering program or distributed generation program application forms and associated fees. An applicant may be eligible to continue participation in the legacy net metering program or distributed generation program when a material modification is made to a customer's previously approved system and it does not violate the requirements of subrule (7) of this rule or R 460.1026. An applicant shall not begin any material modification to the project until the electric utility has approved the revised application, including any necessary system impact study or facilities study. The application must be processed pursuant to part 2 of these rules, R 460.911 to R 460.992.

R 460.1004 Legacy net metering program application and fees.

Rule 104. (1) An electric utility or alternative electric supplier may use an online legacy net metering program application process. An electric utility or alternative electric supplier not using an online application process, may utilize a uniform legacy net metering program application form which must be approved by the commission. An electric utility's legacy net metering program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the legacy net metering program shall concurrently submit a completed legacy net metering program application and interconnection application or indicate on the legacy net metering program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) Where a legacy net metering program application is accompanied by an associated interconnection application, an electric utility shall complete its review of the legacy net metering program application in parallel with processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, the electric utility shall notify the customer whether the legacy net metering program application is accepted, and provide an opportunity for the customer to resolve any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application, or the electric utility may consider the legacy net metering program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter or meters, is installed for the legacy net metering program.

(b) When a legacy net metering program application is filed with an already in-progress interconnection application, the utility may process the legacy net metering application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) When a legacy net metering program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the legacy net metering program application in parallel with the interconnection application, or when the legacy net metering application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the legacy net metering program application pursuant to both of the following:

(i) The electric utility shall review the legacy net metering program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7) within 10 business days. The timelines in R 460.936(7)(a) apply to electric utility notifications. The electric utility shall provide the customer an opportunity to resolve any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(ii) Within 10 business days of notifying the customer that the legacy net metering application has been accepted, the electric utility shall determine whether the appropriate meter is installed for the legacy net metering program.

(d) If a customer approved for participation in the legacy net metering program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer's account to permit the legacy net metering program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed legacy net metering program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The electric utility shall process the legacy net metering program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit the legacy net metering program credit to be applied to the account.

(4) If a legacy net metering program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the deficiency within the timelines pursuant to R. 460.936(7)(b), the alternative electric supplier and electric utility may consider the legacy net metering application withdrawn without refund of the application fees.

(5) If a customer's application for the legacy net metering program is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may terminate the application without refund and shall have no further responsibility with respect to the application.

(6) Customers participating in a legacy net metering program approved by the commission before the commission establishes a tariff pursuant to section 6a(14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment.

(7) The legacy net metering program application fee for electric utilities and alternative electric suppliers may not exceed $50. The fee must be specified on the electric utility's legacy net metering tariff sheet or in the alternative electric supplier's legacy net metering program plan.

R 460.1006 Distributed generation program application and fees.

Rule 106. (1) An electric utility or alternative electric supplier may use an online distributed generation program application process. An electric utility or alternative electric supplier not using an online application process may utilize a uniform distributed generation program application form that must be approved by the commission. An electric utility's distributed generation program application may be combined with an electric utility's interconnection application.

(2) A customer taking retail electric service from an electric utility and applying to participate in the distributed generation program shall concurrently submit a completed distributed generation program application and interconnection application or indicate on the distributed generation program application the date that the customer applied for interconnection with the electric utility and, if applicable, the date the customer received authorization to operate in parallel pursuant to R 460.968.

(a) When a distributed generation program application is accompanied by an associated interconnection application, an electric utility may complete its review of the distributed generation program application concurrently, before, or after processing the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992.

(i) Combined with the notification of interconnection application completeness and conformance pursuant to R 460.936, an electric utility shall notify the customer whether the distributed generation program application is accepted, and provide an opportunity for the customer to remedy any application deficiencies pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) While processing the interconnection application, which may include, but is not limited to, R 460.946 fast track initial review, the electric utility shall determine whether the appropriate meter is installed for the distributed generation program.

(b) If a distributed generation program application is filed with an already in-progress interconnection application, the electric utility may process the distributed generation program application in parallel with the interconnection application pursuant to part 2 of these rules, R 460.911 to R 460.992, and subrule (2)(a) of this rule, if practicable, or adopt the review process pursuant to subrule (2)(c) of this rule.

(c) If a distributed generation program application is filed with an in-progress interconnection application and the electric utility determines it is not practicable to process the distributed generation program application in parallel with the interconnection application or the distributed generation application is filed subsequent to the customer receiving authorization to operate its eligible generator in parallel pursuant to R 460.968, the electric utility shall process the distributed generation program application pursuant to all of the following:

(i) The electric utility has 10 business days to review the distributed generation program application and determine whether to accept the application pursuant to the timelines in R 460.936(6) and (7). The timelines in R 460.936(7)(a) apply to utility notifications. The electric utility shall provide the customer an opportunity to remedy any application deficiencies pursuant to R 460.936(7)(b). If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(ii) Within 10 business days of providing notification to the customer that the distributed generation program application has been accepted, the electric utility shall determine whether the appropriate meter, or meters, is installed for the distributed generation program.

(d) If a customer approved for participation in the distributed generation program requires a new or additional meter or meters, the electric utility shall arrange with the customer to install the meter or meters at a mutually agreed upon time.

(e) The electric utility shall complete changes to the customer's account to permit distributed generation program credit to be applied to the account no more than 10 business days after the necessary meter is installed and all necessary steps in R 460.966 are completed.

(3) A customer taking retail electric service from an alternative electric supplier shall submit a completed distributed generation program application to the alternative electric supplier and provide a copy to the electric utility that provides distribution service.

(a) The alternative electric supplier shall process the distributed generation program application according to the applicable timelines in subrule (2)(a) through (d) of this rule.

(b) The electric utility shall notify the alternative electric supplier when it has provided the applicant authorization to operate the eligible electric generator in parallel pursuant to

R 460.968 and, if applicable, that installation of the appropriate meter or meters is completed.

(c) Within 10 business days of the electric utility's notification, the alternative electric supplier shall complete changes to the applicant's account to permit distributed generation program credit to be applied to the account.

(4) If a distributed generation program application is not approved by the alternative electric supplier, the alternative electric supplier shall notify the customer and the electric utility of the reasons for the disapproval. The alternative electric supplier shall provide the customer an opportunity to remedy the deficiency pursuant to the timelines in R 460.936(7)(b) or withdraw the application. If the customer fails to remedy the application deficiencies within the timelines in R 460.936(7)(b), the alternative electric supplier and electric utility may consider the distributed generation program application withdrawn without refund of the application fees.

(5) If a customer's distributed generation program application is approved, the customer shall have a completed and approved installation within 6 months from the date the customer's application is considered complete, or the electric utility or alternative electric supplier may consider the application withdrawn without refund and shall have no further responsibility with respect to the application.

(6) The distributed generation program application fee for electric utilities and alternative electric suppliers shall not exceed $50. The electric utility shall specify the fee on the electric utility's distributed generation program tariff sheet or in the alternative electric supplier's distributed generation program plan.

(7) The customer shall pay all interconnection costs pursuant to part 2 of these rules, R 460.911 to R 460.992, which include all electric utility costs associated with the customer's interconnection that are not a distributed generation program application fee, excluding meter costs as described in R 460.1012 and R 460.1014.

R 460.1008 Legacy net metering program and distributed generation program size.

Rule 108. (1) If an electric utility or alternative electric supplier reaches the program sizes as defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173 or a voluntarily expanded program above the requirements defined in section 173(3) of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1173, as determined by combining both the distributed generation program and the legacy net metering program customer enrollments, the electric utility or alternative electric supplier shall notify the commission.

(2) The electric utility or alternative electric supplier shall notify the commission of its plans to either close the program to new applicants or expand the program.

(3) The electric utility shall file corresponding revised legacy net metering program or distributed generation program tariff sheets.

(4) The alternative electric supplier shall file a revised legacy net metering program plan or distributed generation program plan.

R 460.1010 Generation and legacy net metering program or distributed generation program equipment.

Rule 110. New legacy net metering program or distributed generation program equipment and its installation must meet all current local and state electric and construction code requirements, and other standards as specified in part 2 of these rules, R 460.911 to R 460.992.

R 460.1012 Meters for legacy net metering program.

Rule 112. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility may determine the customer's net usage using the customer's existing meter if it is capable of reverse registration or may install a single meter with separate registers measuring power flow in each direction. If the electric utility uses the customer's existing meter, the electric utility shall test and calibrate the meter to assure accuracy in both directions. If the customer's meter is not capable of reverse registration and if meter upgrades or modifications are required, the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to the legacy net metering program customer. The cost of the meter or meter modification is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter, if requested by the customer, at cost.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a legacy net metering program customer. The cost of the meter or meters is considered a cost of operating the legacy net metering program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above that for meters provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter is considered a cost of operating the legacy net metering program.

(3) For a customer with a generation system capable of generating more than 150 kWac, the electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter upgrades are necessary to provide this functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a legacy net metering program participant or the legacy net metering program.

R 460.1014 Meters for distributed generation program.

Rule 114. (1) For a customer with a generation system capable of generating 20 kWac or less, an electric utility shall determine the customer's power flow in each direction using the customer's existing meter if it is capable of measuring and recording power flow in each direction. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring and recording the customer's power flow in each direction at no additional charge to the distributed generation program customer. The cost of the meter or meter modification is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring and recording the power flow in each direction to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter at cost, if requested by the customer.

(2) For a customer with a generation system capable of generating more than 20 kWac and not more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring and recording power flow in each direction and the generator output. If the customer's meter is not capable of measuring and recording the customer's power flow in each direction along with the generator output, and if meter upgrades or modifications are required, all of the following apply:

(a) An electric utility serving 1,000,000 or more customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions at no additional charge to a distributed generation program customer. If the electric utility provides the upgraded meter at no additional charge to the customer, the cost of the meter is considered a cost of operating the distributed generation program.

(b) An electric utility serving fewer than 1,000,000 customers in this state shall provide a meter or meters capable of measuring the flow of energy in both directions to customers at cost. Only the incremental cost above the cost for the meter provided by the electric utility to similarly situated non-generating customers shall be paid by the eligible customer.

(c) An electric utility shall provide a generator meter. The cost of the meter shall be considered a cost of operating the distributed generation program.

(3) For a customer with a methane digester generation system capable of generating more than 150 kWac, an electric utility shall utilize a meter or meters capable of measuring the flow of energy in both directions and the generator output. If meter

upgrades are necessary to provide such functionality, the customer shall pay the cost of providing any new meters.

(4) An electric utility deploying advanced metering infrastructure shall not charge the cost of advanced meters to a distributed generation program customer or the distributed generation program.

R 460.1016 Billing and credit for legacy net metering program customers taking service under true net metering.

Rule 116. (1) Legacy net metering program customers with a system capable of generating 20 kWac or less qualify for true net metering. For customers qualifying for true net metering, the net of the bidirectional flow of kWh across the customer interconnection with the electric utility distribution system during the billing period or during each time-of-use pricing period within the billing period, including excess generation, shall be credited at the full retail rate.

(2) The credit for excess generation, if any, shall appear on the next bill. Any excess credit not used to offset current charges must be carried forward for use in subsequent billing periods.

R 460.1018 Billing and credit for legacy net metering program customers taking service under modified net metering.

Rule 118. (1) Legacy net metering program customers with a system capable of generating more than 20 kWac qualify for modified net metering. A negative net metered quantity during the billing period or during each time-of-use pricing period within the billing period reflects net excess generation for which the customer is entitled to receive credit. Standby charges for customers on an energy rate schedule must equal the retail distribution charge applied to the imputed customer usage during the billing period. The imputed customer usage is calculated as the sum of the metered on-site generation and the net of the bidirectional flow of power across the customer interconnection during the billing period. The commission shall establish standby charges for customers on demand-based rate schedules that provide an equivalent contribution to electric utility system costs. Standby charges may not be applied to customers with systems capable of generating 150 kWac or less.

(2) The credit for excess generation must appear on the next bill. Any excess kWh not used to offset current charges must be carried forward for use in subsequent billing periods.

(3) A customer qualifying for modified net metering shall not have legacy net metering program credits applied to distribution charges.

(4) The credit per kWh for kWh delivered into the electric utility's distribution system must be either of the following as determined by the commission:

(a) The monthly average real-time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory or for a legacy net metering program customer on a time-based rate schedule, the monthly average real time locational marginal price for energy at the commercial pricing node within the electric utility's distribution service territory during the time-of-use pricing period.

(b) The electric utility's or alternative electric supplier's power supply component, excluding transmission charges, of the full retail rate during the billing period or time-of-use pricing period.

R 460.1020 Billing and credit for distributed generation program customers.

Rule 120. As part of an electric utility's rate case filed after June 1, 2018, the commission shall approve a tariff for a distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this rule does not apply to customers participating in a legacy net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this rule, who continue to participate in the program at their current site or facility as described by R 460.1026.

R 460.1022 Renewable energy credits.

Rule 122. (1) An eligible electric generator shall own any renewable energy credits granted for electricity generated under the legacy net metering program and distributed generation program.

(2) An electric utility may purchase or trade renewable energy credits from a legacy net metering program or distributed generation program customer if agreed to by the customer.

(3) The commission may develop a program for aggregating renewable energy credits from legacy net metering program and distributed generation program customers.

R 460.1024 Penalties.

Rule 124. Upon a complaint or on the commission's own motion, if the commission finds after notice and hearing that an electric utility has not complied with a provision or order issued under part 5 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1171 to 460.1185, the commission shall order remedies and penalties as necessary to make whole a customer or other person who has suffered damages as a result of the violation.

R 460.1026 Legacy net metering grandfathering clause.

Rule 126. A customer participating in a legacy net metering program approved by the commission before the commission establishes the initial distributed generation program tariff pursuant to R 460.1020 may elect to continue to receive service under the terms and conditions of that program for up to 10 years from the date of initial enrollment. "Initial enrollment," as used in this rule, means the date a customer or site initially enrolled in a legacy net metering program as described in the electric utility's tariff. A customer participating in a legacy net metering program who increases the nameplate capacity of its generation system after the effective date of an electric utility's distributed generation program tariff is no longer eligible to participate in the legacy net metering program.

From:	Marco Menezes
To:	LARA-MPSC-EDOCKETS
Subject:	Distributed Generation Rules
Date:	Monday, June 27, 2022 9:36:57 AM

As the MPSC considers updating Michigan's distributed generation rules, it should undertake a full "Value of Solar" study to assist in re-determining rates of reimbursement for power added to the grid by small, non-commercial distributed producers. A comprehensive analysis which assigns economic value to avoided externalities (pollution, climate change, etc) was not done when the current rates were set. Instead, the unsubstantiated, utility-promoted myth that residential solar is somehow "subsidized" by other rate-payers was uncritically accepted as fact. With the current low market penetration of renewables in the state, assigning the same "avoided cost" valuation to new renewable and fossil fuel choices was and remains an "apples to oranges" comparison.

The resulting gross undervaluation of distributed generation underpinning current rate structure has significantly depressed expansion of residential solar in our State at a critical time of essential transition away from fossil fuels.

Marco Menezes

Hersey, MI

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
LOCAL 17
17000 West Twelve Mile Road • Southfield, Michigan 48076-2112
(248) 423-4540 • FAX (248) 423-9277

James Shaw
Business Manager & Financial Secretary

June 21, 2022

RE: Comment on proposed changes to Interconnection Rules from Local Union No. 17, IBEW (U-20890)

To Whom it May Concern,

My name is James Shaw. I am the Business Manager and Financial Secretary at Local 17 International Brotherhood of Electrical Workers. Local 17 appreciates the opportunity to share with the Commission our perspective and experience regarding interconnection and its impact on our 4,000 members in Southeast Michigan. Over the last 130 years Local 17 has been representing employees that work in the outside electrical industry. Many of our members are Journeyman Lineman, Journeyman Tree Trimmers, Journeyman Substation Technicians, URD Cable Splicers, and Underground Installers. All of these members work directly or indirectly for DTE Energy on building and maintaining the electrical grid for DTE Energy's customers.

Safety and reliability are paramount not only to our members, but to their families as well. One of our concerns with the currently proposed interconnection rules is a change that would allow distributed energy resources to deliver uncontrolled energy export to DTE Energy's distribution system. That would be a dramatic change from the previous standard of fractions of a second to over half a minute of dangerous DER operation. This rule change could expose our members working on the system to be exposed to an unexpected, unsafe grid condition. It is also inconsistent with industry standards and practices and has the potential to impact other customers on a circuit, including residents, and businesses that include hospitals and schools.

A related concern is that the updated rules rewrote the definition of the limited export of power, which will allow the distributed energy generation owners to continue to operate overloaded or malfunctioning equipment that could impact the power reliability and power quality of other customers. This condition would place our members, customers, and the public knowingly and needlessly at risk due to failures, fires, or even explosions. Under the existing rules, DTE has integrated several limited export projects successfully and has worked with customers and installers to successfully and cooperatively identify safe, reliable, and cost-effective ways to implement limited export projects.

Another critical safety concern in the revised rules is the reductions in the screening process for the proposed distributed resources. As written, this prevents DTE from taking action to implement even simple screens such as "Is the existing service or transformer sufficiently sized to accommodate the interconnection?" or "Is hosting capacity available on the circuit?". The currently proposed rules provide no way to prevent such interconnections before they become a safety concern involving overloaded or over-voltage equipment. Due to screening limitations the only resolution to having this unsafe equipment connected to the grid set forth in the revised rules is to first allow its construction and interconnection, then require after-the-fact disconnection.

Local 17 recognizes that some customers share our enthusiasm for clean energy and want to be more involved in their energy supply. However, we also think everyone agrees that safety and distribution system reliability must remain the paramount considerations.

Sincerely,

James A Shaw

James A. Shaw
Business Manager/Financial Secretary
Local Union No. 17, IBEW

JS:mh/opeiu 42, afl/cio.

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June 27, 2022

Lisa Felice
Executive Secretary
Michigan Public Service Commission
PO Box 30221
Lansing, MI 48909-7721

Re: Case No. U-20890
Michigan Electric Cooperative Association

Dear Ms. Felice:

Enclosed for electronic filing please find the Comments Of The Michigan Electric Cooperative Association in the above-referenced matter.

If you have any questions, please contact me.

Sincerely,

DYKEMA GOSSETT PLLC

Richard J. Aaron

111253.000001

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No. U-20890

COMMENTS OF THE MICHIGAN ELECTRIC COOPERATIVE ASSOCIATION

The Michigan Electric Cooperative Association[1] ("MECA") appreciates the time and effort the parties have spent on developing the proposed rules in this case. Accordingly, MECA respectfully submits these comments in response to the May 26, 2022 Order of the Michigan Public Service Commission (the "Commission") providing for renewed comments on its proposed Interconnection and Distribution Generation Standards ("Proposed Rules"):

Introduction

Paramount to MECA and its members is the safety and reliability of their distribution systems—which support a wide variety of commercial and residential activity throughout the state. MECA's collective customer base is located in rural and historically underserved areas of Michigan and the health and livelihood of many customers within MECA's collective service territory depends on a safe and reliable distribution grid. It is vital for MECA cooperatives to have

[1] MECA is a Michigan non-profit corporation, incorporated on July 26, 1978. MECA serves as the statewide association for Michigan's rural electric distribution cooperatives, one generation and transmission cooperative, and one alternative electric supplier, who, combined, provide electricity to more than 650,000 Michigan residents in all or part of 58 Michigan counties. Currently, all of MECA's member cooperatives are member-regulated under 2008 PA 167, as amended, MCL 460.31 *et seq*.

the tools and ability to study and mitigate potential critical safety issues. While it is apparent that the legacy Interconnection and Distribution Generation Standards (pre-March 17, 2022 amendment) (the "original MIXDG rules") need to be revised because of the proliferation of third-party designed devices and the increasing popularity of distributed energy resources ("DERS"), it is important that revisions to the original MIXDG rules do not come at the cost of the MECA cooperatives' ability to test and approve all proposed interconnections to their distribution systems. Protecting this right is critical to ensuring the safety of the MECA cooperatives' customers, employees, and infrastructure. There are also a number of proposed rule changes that require current clarification—particularly because MECA cooperatives have already developed and submitted to stakeholders proposed interconnection procedures and forms which could be in conflict with the March 17, 2022 amended version of the Rules and the Proposed Rules.

MECA appreciates the re-opening of this docket for the opportunity to submit additional comments and that, before the Commission approves its final rules, all parties have the opportunity to comment and weigh in on the proposals.

Comments

1. The Proposed Rules do Not Adequately Safeguard the MECA Cooperatives' Ability to Provide a Safe and Reliable Distribution System.

First and foremost, the Proposed Rules do not put enough control over vetting safety and reliability measures in the hands of the MECA cooperatives. While the comments below outline the specific ways in which these measures are lacking, it is important to note that when these issues are taken as a whole, the MECA cooperatives (and indeed all electric utilities under the rules) likely stand to provide less reliable energy to their customers as a direct result of the Proposed Rules, if those rules are not modified.

These concerns regarding the safety, reliability and control of the MECA cooperatives' distribution system also implicate their ability to manage their privately owned property. By preventing the MECA cooperatives from adequately protecting its systems from DER exports, particularly during outage (i.e., fault) conditions, the Proposed Rules physically interfere with the MECA cooperatives' ability to manage the safety and reliability of their distribution system. The physical appropriation of property—even temporarily—is impermissible under the Fifth Amendment. *Cedar Point Nursery v Hassid*, 141 S. Ct. 2063; __ U.S. __ (2021) ("The fact that a right to take access is exercised only from time to time does not make it any less a physical taking.").

2. The Proposed Rules Should Reintegrate Allowances for Additional Initial Screening Procedures.

The Proposed Rules eliminated a previous allowance for additional supplemental review screens and thereby impair the ability of MECA to provide meaningful review in their interconnection procedures from Mich Admin Code, R. 460.950. Eliminating this important reliability safeguard will have potentially adverse outcomes. Additional supplemental review screens should be regarded as safety measure for the MECA cooperatives and not administrative "red tape." In addition, the additional screens also benefit DER parties by identifying problems before they arise. Prior to the Proposed Rules, an electric utility was required to provide a "detailed technical rationale" and an "explanation of the technical justification for the additional screen" to implement additional supplemental screens—i.e., additional screens were not implemented arbitrarily. However, the Proposed Rules eliminated this ability to require additional screens where needed for technical reasons and therefore forces MECA cooperatives to fast track interconnections that have not been properly vetted. In turn, the Commission risks the reliability of the distribution system and the safety of other customers, unless the Final Rules reinstate the ability to implement additional screens. As the MECA cooperatives noted in their Answer to the DTE Petition for Rehearing:

> The proposed rules effectively allow dangerous operation until the project trips offline or the electric grid comes back online. This amount of time (short or long) can cause a transformer to fail catastrophically (potentially including a fire), seriously impact power quality to adjacent customers (potentially including appliance failures), and even feed into faults (both on the local distribution system and the upstream affected systems) that puts public health and safety at risk.

This issue goes essentially unaddressed in the Proposed Rules and there is no opportunity for the MECA cooperatives to assess a potentially dangerous interconnection in an appropriate timeframe.

The initial screens in Rules 46 and 50 are essential to the MECA cooperatives to determine if upgrades to the distribution system is required. Upgrades are essential for some interconnections to maintain the reliability and safety of the of grid and public, and potential upgrades need to be identified as soon as possible. Additionally, upgrades add costs that are the responsibility of the DER. It is important that the MECA cooperatives provide certainty to the DER as early as possible because it may dictate how the DER wants to proceed with their project.

The MECA cooperatives recommend reinserting the additional supplemental review screens into the Proposed Rules.

3. The Proposed Rules limit MECA Cooperatives' Ability to Control the Safety of DER Power Export Limits.

The Proposed Rules limit MECA cooperatives' ability to control the safety of their distribution system by limiting the actions that the MECA cooperatives can take when controlling for DER power exports. The Proposed Rules provide that "[t]o prevent impacts on system safety and reliability, any inadvertent export from a DER must comply with the limits in subdivisions (e) or (f) of this subrule. . . . Other means not listed in this subrule may be utilized to limit export *if mutually agreed upon* by the electric utility and the applicant." Mich Admin Code, R 460.980(4).

In subdivisions (e) and (f), the only safety measures permitted are in the sole control of the DER to monitor and implement.

The addition of subpart (4) in the Proposed Rules creates significant safety and liability concerns for the MECA cooperatives. Although the Proposed Rules specify that "failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the DER entering an operational mode where no energy is exported across the point of common coupling to the distribution system,"[2] it will be *MECA cooperatives' distribution system* that bears the burden of the loss of the DER's Power Control System. Therefore, the Proposed Rules put the monitoring and control over safety measures that will protect the MECA cooperatives' distribution system entirely within the hands of a third party. This is not a suitable mechanism to create a timely and appropriate response that protects the MECA cooperatives' distribution system and its reliability. Further, limiting the possible responses of the MECA cooperatives to protect "system safety and reliability" to the mechanisms provided in subdivisions (e) and (f) does not provide adequate flexibility for the MECA cooperatives to take the actions necessary to protect their distribution system in the event of excessive DER capacity exports.

4. The Proposed Rules Adopt an Arbitrary Definition of "Business Days".

The Proposed Rules provide the following definition of "Business Days"

> "Business day" means Monday through Friday, starting at 12:00:00 a.m. and ending at 11:59:59 p.m., ~~excluding the following holidays: New Year's Day, Martin Luther King Jr. Day, Presidents Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Christmas Eve, Christmas Day, and New Year's Eve, Election Day, the day after Thanksgiving,~~ **electric utility holidays** ~~and any day that meets the criteria of catastrophic conditions as defined in R 460.702(f)~~ **in which electric service is interrupted for 10% or more of an electric utility's**

[2] Mich Admin Code, R 460.980(4)(e).

customers. A list of electric utility holidays shall be provided in the electric utility's interconnection procedures.

This proposed definition is problematic for a number of reasons. First, there are references throughout the proposed rules where calendar days or business days have not been specified. *See, e.g.*, Mich Admin Code, R 460.990. The Proposed Rules should be amended so that each reference to a "day" specifies whether it is a business day or a calendar day. Second, the electric service interruption standard does not reflect the reality of the MECA cooperatives' system of business administration. MECA cooperatives tend to have smaller pool of customers than larger utilities, and those customers tend to be clustered in smaller geographic areas. It is much more likely for a weather event to result in a loss of a business day for MECA cooperative than it is for a larger utility like DTE. Particularly because electric service interruption days will likely only be measured in retrospect, this definition creates difficulties in tracking and administration for the Staff of MECA cooperatives. Third, even days with electric service outages for certain customers are days when the staff of the MECA cooperatives are still working. There is no differentiation in this proposed definition between days where staff and employees, or a majority of staff and employees, are *unable* to work because of circumstances beyond their control. The proposed definition is not a good measure of what a business day actually is. The MECA cooperatives recommend elimination of the electric service interruption clause altogether.

5. It is Unclear How the Proposed Rules Should Be Applied to Alternative Energy Suppliers.

While Alternative Energy Suppliers ("AES") are included in the definition of "electric utility" under the Rules, an AES does not own distribution system infrastructure, and therefore it is unclear how the Proposed Rules should be applied. One alternative is that the AES is subject to the interconnection standards of the electric utility that the customer is interconnected to, however, this requires the AES to track and coordinate a variety of interconnection standards, again for facilities that it does not own, operate, or maintain. MECA recommends exempting AESs from the Proposed Rules and requiring that a customer coordinate an interconnection request directly with the interconnecting electric utility. This would eliminate extra administrative burdens on both the AES and the Commission. It would also streamline the interconnection process for the customer.

6. MECA Cooperatives Support the Addition of Rule 56, Adding Flexibility to Tailor Studies of Interconnection Applications.

As a collective of smaller electric utilities under the Rules, the MECA cooperatives appreciate the flexibility provided by the addition of Mich Admin Code, R 460.956, which allows for an alternative process to study interconnection applications different from the process described in the rules. MECA supports the addition of Rule 56.

7. MECA Cooperatives Support the Addition of Rule 82(5)(d) and the Flexibility it Provides in Types of Studies of Applications.

Similar to the previous comment, the MECA cooperatives are supportive of the added language in Mich Admin Code, R 460.982(5)(d). Expedited studies put additional administrative pressure on smaller utility providers such as the MECA cooperatives and the MECA cooperatives appreciate the flexibility to decline to provide expedited studies.

Conclusion

The MECA cooperatives appreciate this opportunity to provide additional comments, however, the current Proposed Rules do not provide the tools necessary to ensure a safe and reliable electric grid. In addition, there also remains a need for clarifications of certain rules. The MECA cooperatives respectfully urge the Commission to consider the comments above and revise the Proposed Rules accordingly.

Respectfully submitted,

Michigan Electric Cooperative Association

Dated: June 27, 2022

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection reconciliation of its power supply cost recovery and distributed generation, and rescind legacy interconnection and net metering rules.	)))))	Case No. U-20890

COMMENTS OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
AND VOTE SOLAR

June 27, 2022

The Environmental Law and Policy Center, the Ecology Center and Vote Solar, (collectively, the Clean Energy Organizations, or "CEO") timely file these comments on the draft set of rules titled Interconnection and Distributed Generation Standards ("MIXDG rules") consistent with the Michigan Public Service Commission's ("MPSC" or "Commission") May 12, 2022 Order. The CEO, alongside utilities and other stakeholders, participated in the working groups that informed Commission Staff's initial draft of the rules. These working groups were open to any interested person. All participants were focused on providing information and perspectives that would help Commission Staff develop clear rules that provided for safe and reliable interconnection. These early discussions were helpful in identifying a broad spectrum of concerns for Staff to consider in developing a set of potential rules for the Commission to study. The Commission put a set of draft rules out for formal public comment on September 9, 2021, consistent with the Michigan Administrative Procedures Act ("Draft MIXDG rules").

The CEO submitted comments on the Draft MIXDG rules on November 1, 2021. The Commission issued an order responding to comments and approving a revised version of the MIXDG rules for final adoption on March 17, 2022 ("MIXDG rules"). On April 14, 2022, various monopoly utilities petitioned for rehearing of the Commission's March 17 Order, arguing that untimely comments had been considered by the Commission.[1] The CEO answered the petition on May 5, 2022. On May 12, 2022, the Commission agreed to provide a second public hearing on the MIXDG rules and, after engagement with the proper regulatory authorities, on May 26 the Commission issued an Order setting a comment deadline of 5:00 p.m. (Eastern time) on June 27, 2022.

[1] It appears that commenter Sunrun timely submitted comments and a document Sunrun believed contained redlines, but in fact inadvertently provided a clean copy of the rules instead of the redline. When Staff noted that the redlines were not appearing in the document, Sunrun was notified, and the correct file was provided. (See May 12, 2022 Order at 3).

The CEO are generally supportive of the MIXDG rules as approved by the Commission on March 17, 2022. To be clear, no set of draft or final rules in this proceeding has reflected all of the CEO recommendations. Nor would the CEO necessarily expect that to be the case, given the diversity of perspective represented in the commenting parties. The CEO incorporate herein, and do not repeat, previous comments on the Draft MIXDG rules. Failure to address a particular aspect of the Draft MIXDG rules should not be construed as agreement, nor constitute waiver of any legal right to participate in any challenge to the rules.

A. The proposed MIXDG rule is consistent with the Commission's statutory authority under MCL 460.1173.

In 2016, the Michigan legislature established a distributed generation program by passing Act 342, which amended Act 295 of 2008. Act 342 authorizes the Commission to promulgate rules "necessary to implement" the distributed generation program. MCL 460.1173(1). It also unambiguously directs the Commission to develop "statewide uniform interconnection requirements for all eligible electric generators." MCL 460.1173(6)(a).

(1) The time limits for approval of parallel operation in the MIXDG rules recognize reliability and safety complications. (MCL 460.1173(1)).

Act 342 directs the Commission that:

> Any rules adopted regarding time limits for approval of parallel operation shall recognize reliability and safety complications including those arising from equipment saturation, use of multiple technologies, and proximity to synchronous motor loads.

MCL 460.1173(1). "Parallel operation" is defined in the MIXDG rules as the operation, for longer than 100 milliseconds, of a DER while connected to the energized distribution system. *See* MIXDG rules Definitions at (y). This section of the statute applies specifically to "time limits for approval" of parallel operation. In other words, the legislature wanted to be sure that the

Commission considered how reliability and safety complications impact the deadlines established in interconnection rules.

Here, the Commission determined, based upon its own expertise and information provided in comments, that the portions of the MIXDG rules regarding time limits for approval of parallel operation recognize reliability and safety complications that are raised in the interconnection context. MCL 460.1173(1). The Commission explicitly acknowledged and acted upon comments from utilities recommending changing the term "days" to "business days," excluding utility holidays from the definition of "business days," and increasing the length of certain deadlines. (March 17, 2022 Order at 8-10). The Commission also recognized utility safety and reliability concerns with respect to time limits in the simplified track review process. In response to utility comments, the Commission expanded the timeline for utility specification of equipment an application from 10 business days to 20 business days. (March 17, 2022 Order at 22). With respect to inspection, testing, and commissioning, the Commission recognized DTE's concerns that a longer timeframe was necessary to enable utilities to coordinate with an applicant and physically visit the project site. In recognition of DTE's comments related to reliability and safety, the Commission modified the draft rules to provide additional time for larger projects. (March 17, 2022 Order at 27). In recognition of potential reliability and safety complications, the Commission recognized the need for smaller utilities to have longer time frames. The Commission added a new rule providing an additional 10 business days for each timeline in the ruleset for electric utilities with less than 1,000,000 Michigan customers. (March 17, 2022 Order at 34).

(2) The MIXDG rules are designed to protect electric utility workers and equipment and the general public. (MCL 460.1173(6)(a)).

In addition to the general authority to promulgate rules necessary to implement the distributed generation program, the Commission has an affirmative duty to develop statewide uniform interconnection requirements. MCL 460.1173(6)(a). These statewide rules must be designed to "protect electric utility workers and equipment and the general public." MCL 460.1173(6)(a). The statute delegates this fact-finding exercise to the administrative and technical expertise of the Commission. The Commission's finding that the MIXDG rules are designed to protect electric utility workers and equipment, as well as the general public, is based on its expertise. *Slis v. State*, 332 Mich. App. 312, 353, 956 N.W.2d 569, 592, *appeal denied*, 506 Mich. 912, 948 N.W.2d 82 (2020) ("the principle of giving due deference to an agency with regard to fact-finding because of its expertise has become well established in our civil jurisprudence"); *Travelers Ins. Co. v. Detroit Edison Co.*, 465 Mich. 185, 198, 631 N.W.2d 733 (2001) ("[A]dministrative agencies possess specialized and expert knowledge to address issues of a regulatory nature.")

The MIXDG rules reflect the growing use of energy storage in Michigan and the broad availability of power-limited export systems. The Midwest states of Illinois and Minnesota have interconnection rules that enable power-limited export systems.[2] Indeed, to omit rules governing power-limited export would invite damage to utility equipment and potentially harm utility workers and the general public. Uniform statewide definitions and standards for energy storage protect utility workers and equipment and the general public by creating clarity, transparency, and predictability in the process. The Commission's limited-export standards are consistent with the 2019 Model Interconnection Rules from the Interstate Renewable Energy Council ("IREC"), a non-profit organization that has been instrumental in assisting several state utility commissions in

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[2] Illinois Commerce Commission. Docket 20-0700. Final Order. May 25, 2022. Available at: https://www.icc.illinois.gov/docket/P2020-0700/documents/324414. See proposed rule in MN Pub. Util. Comm., Dkts. E999/CI-16-521 & E999/CI-01-1023, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611.

rules that focus on distributed energy resource interconnection procedures. Relevant and responsive to concerns raised by utilities in their petition for rehearing, IREC provided a memo to Vote Solar explaining that the MIXDG rules do not raise safety and reliability concerns as claimed by the utilities. (*See* Attachment A, June 24, 2022 memo from Brian Lydic, Chief Regulatory Engineer, IREC to Vote Solar). IREC's memo supports the Commission's conclusion that the MIXDG rules are designed to "protect electric utility workers and equipment and the general public." MCL 460.1173(6)(a).

(3) The MIXDG rules provide an opportunity for utility testing and approval of interconnection consistent with Michigan law. (MCL 460.1173(6)(b)).

Act 342 specifies that "Both of the following must be completed before equipment is operated in parallel with the distribution system of the utility: (i) Utility testing and approval of interconnection, including all metering. (ii) Execution of a parallel operating agreement." (MCL 460.1173(6)(b)). Rule 460.966 specifically allows for inspection, testing and commissioning of devices, and sets straightforward timeframes for completing those tasks.

In its request for a rehearing, the utilities seemed to think that Rules 460.920 and 460.980 foreclosed the utility's "right" to test and approve all proposed interconnections. (Petition for Rehearing at 7). Rule 460.920 requires each utility to develop interconnection procedures that must be approved by the Commission. These procedures must include acceptable methods or standards for power-limited export DERs in compliance with allowances in Rule 460.980. Rule 460.980 requires utility interconnection procedures to include "acceptable methods for power limited export DER so that the DER capacity considered by the electric utility for reviewing the interconnection application is only the amount capable of being exported." Rule 460.980(4). Rule 460.980(4)(e) allows DERs to use a system that has been certified to ensure that export of energy will stop when necessary to protect utility workers and equipment and the general public.

The utilities appear to argue that this provision in the MIXDG rules, which allows the use of thoroughly tested and nationally certified devices, is inconsistent with the statutory requirement that utilities "test and approve" equipment before interconnection. The statute cannot reasonably be interpreted to mean that before any export-limiting equipment is interconnected, utilities are entitled to individually test and approve that specific piece of equipment.

It would be unreasonable to construe the statute as directing the Commission to develop statewide interconnection requirements that prevented any member of the public from interconnecting until their specific piece of equipment had been inspected by the utility. It is perfectly reasonable to interpret the statute as allowing utilities to rely on certification of a device rather than individual testing. Certified devices have met "acceptable safety and reliability standards by a nationally recognized testing laboratory" in conformance with technical standards. (*See* MIXDG rules Definitions at (m)). These testing laboratories must be recognized by the accreditation program of the United States Department of Labor Occupational Safety and Health Administration. (*See* MIXDG rules Definitions at (u)). Furthermore, it is clear from the number of states who have incorporated certification into limited-export rules that national certification obviates the need for individualized testing of devices. (*See also* Attachment A).

* * * * *

The issues raised by the utilities in the petition for rehearing are meritless, and the Commission should not modify the MIDXG rules on the basis that they raise safety or reliability concerns.

Respectfully submitted,

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Dated: June 27, 2022

MEMORANDUM

Date: June 24, 2022
To: Vote Solar
From: Brian Lydic, Chief Regulatory Engineer, Interstate Renewable Energy Council (IREC)

This multi-part memorandum serves to address certain technical issues raised by DTE Electric Company's and Consumers Energy Company's ("the Petitioners") Joint Petition for Rehearing of April 14, 2022[1] ("the Petition"). The Petitioners raise a number of concerns regarding due process and unsafe or unreliable electrical conditions that could arise due to the filed Public Service Commission Interconnection and Distributed Generation Standards ("MIXDG"). Here, I address the safety and reliability concerns raised in the Petition's section B, namely the general conclusion that:

"The MIXDG rules conflict with the authorizing statutes by failing to consider, and ultimately creating safety and reliability concerns."[2]

The Petitioners focus on concerns around allowing certified Power Control Systems ("PCS"), the effects of inadvertent export ("IE") on conductors and transformers (or distribution system equipment more generally), and the ramifications of fast track eligibility limits and certain screens being based on the limited-export value. This memo serves to refute the characterization of certain aspects of these arguments based on experience, standards and emerging best practices, and concludes that the MIXDG rules are in line with emerging best practices that maintain safety and reliability of the distribution system.

I. Inadvertent export is an understood phenomenon supported by field applications and standards.

IREC supports the allowance for limited-export systems as defined by R 460.980(4). This language is similar to that used in the new Illinois Part 466 interconnection rules[3] (Section 466.75) as well as that proposed by the Toolkit & Guidance for the Interconnection of Energy Storage & Solar-Plus-Storage[4] ("BATRIES Toolkit", Chapter III). Therefore, we believe it reflects innovation in best practice for the interconnection evaluation of Distributed Energy Resource (DER) systems that electronically limit export power. Limited-export systems including those using relays or Power Control Systems can introduce inadvertent export, which is export of power exceeding the "ongoing operating capacity"[5] and for a limited duration, generally due to fluctuations in load-following behavior. While some utilities may not be currently familiar with the phenomenon, the use of systems that generate IE is supported by existing experience and standards.

[1] DTE Electric Company's and Consumers Energy Company's Joint Petition for Rehearing, Case No. U-20890, April 14, 2022
[2] Petition for Rehearing, p. 12
[3] Title 83: Public Utilities Chapter I: Illinois Commerce Commission Subchapter c: Electric Utilities Part 466 Electric Interconnection of Distributed Energy Resources Facilities https://www.icc.illinois.gov/docket/P2020-0700/documents/324414/files/564658.pdf
[4] BATRIES Toolkit, p. 53 – 55, https://energystorageinterconnection.org/resources/batries-toolkit/
[5] As defined in R 460.901b

a. **PCS equipment has been used in HI, CA and elsewhere with no known safety or reliability issues.**

The California Public Utilities Commission first authorized changes to Rule 21 (the state's interconnection procedures) in Decision 16-06-052 adopted on July 1, 2016 to allow for the use of PCS. These changes, including adoption of section Mm of the rules, were implemented through advice letter filings in 2016 (see, e.g., San Diego Gas & Electric Company Advice Letters 2959-E and 2959-E-A). Hawaii also began allowing the use of power controls systems in late 2015. See Hawaiian Electric Co., Rule 22. With around six years of field experience with these systems in the United States, no known safety or reliability issues have arisen due to IE. It is IREC's understanding that similar equipment has been used elsewhere in the world (e.g., Europe) for even longer. Note that these types of systems have been "self-certified" by the manufacturers in the past before UL published a test procedure for PCS in 2019.

b. **The National Electrical Code provides for fire safety and allows for inadvertent export up to 30 seconds in duration.**

The National Electrical Code ("NEC") 2020 edition, in section 705.13, permits the use of certified PCS to ensure equipment thermal limits are not exceeded. In doing so, the NEC does not include additional limitations on the number or frequency of inadvertent export events, nor does it include additional requirements for safety that are covered by certification. An example use case for the PCS is to limit currents from multiple DER units to maintain the current output of the total system within the capabilities of a conductor or bus to which they are all connected. This is a very similar use case to the export-limiting function also allowed by PCS addressed by R 460.980(4)(e), which must ensure that export is maintained within the distribution system equipment capabilities.

c. **The UL 1741 Certification Requirement Decision ("CRD") for Power Control Systems supports the use of Power Control Systems inclusive of inadvertent export for NEC conductor loading and utility interactive export-limiting applications.**

The potential for use of certified equipment for PCS has been bolstered since UL published the CRD for PCS in March 2019. This testing protocol can be used today by manufacturers to verify compliance with their Nationally Recognized Testing Laboratory. These systems can work either for conductor protection in the NEC context, or for export limitation, or both. Both use cases would have the effect of controlling power at the point of common coupling to a set value. The CRD was developed with the input of utilities, safety experts and manufacturers to ensure safe operation. The BATRIES Toolkit notes some specific assurances provided by the multiple tests included in the CRD[6]:

"To mitigate the potential for disruption, it mandates that the time the PCS takes to respond to inadvertent export, known as the open loop response time (OLRT), be measured through a series of load drops and step changes in generation. It requires that

[6] BATRIES Toolkit, p. 160 - 161

the OLRT be no greater than 30 seconds (although manufacturers can—and do—support faster response times, in some cases to meet regulatory requirements)."

"In addition to the OLRT, the CRD requires testing of abnormal conditions such as loss of control circuit power, loss of control signal, and loss of signal from sensors due to open circuit or short circuit. These conditions must be appropriately detected during both startup and normal operation. The PCS also checks for incorrect installation at startup. Some exceptions to these tests are provided if additional protections are put in place for the PCS. Power must be kept at or below the set limit during any of the abnormal conditions."

d. Conclusion.

Power Control Systems and export-limiting devices more broadly have been used in DER systems for a number of years. Standards that support their safe use have been created, and innovative best practice defined in recent publications supports the inclusion of certified limited-export systems in interconnection rules. Many interconnection rules have not been updated in some time and can benefit from inclusion of concepts that support energy storage interconnection and the ability to control DER. The focus of states should be to implement these findings and standards, while continuing to learn from the updated interconnection rules as a process of continual adjustment.

II. "Dangerous operation" is mischaracterized by the utilities.

Despite the use of power-limiting devices and attendant inadvertent export being supported by standards, the Petitioners refer to IE as "dangerous operation" as in the following excerpt[7]:

"The proposed rules effectively allow 32 seconds of dangerous operation until the project needs to come back into compliance. This short amount of time can cause a transformer to fail catastrophically (potentially including a fire) and seriously impact power quality to adjacent customers (potentially including appliance failures)."

This broad characterization does not hold up upon review of conductor and transformer engineering standards. The following discussion references engineering standards to show that IE is not a dangerous condition for conductors or transformers.

a. Inadvertent export is generally driven by changes in load, not nameplate ratings.

It is important to note up front that the evaluation of export power is appropriate in the interconnection evaluation process, since the nameplate rating of a DER may not actually present itself at the DER terminals due to normal operation. For instance, multiple storage units may be connected in parallel to a residential load panel in order to increase the total kilowatt-hour capacity of the storage system. If these units are, for example, rated at a power of 5 kW each and 10 kWh, three units in parallel would have a nameplate rating of 15 kW and capacity of 30 kWh. However, if the customer is

[7] Petition for Rehearing, p. 8

restricted from exporting any stored power and utilizes a PCS to manage the power output of the three storage units, such that they are generally non-exporting (with allowance for IE), then the total output of the combined storage system will only ever match the load at the house. If the maximum load of the house is 10 kW, then the maximum the total output of the storage system would ever be is 10 kW. Inadvertent export is generally driven by changes in load, so the maximum IE that would occur if all house load turned off at once would be 10 kW. Short of a failure of the certified PCS controls, the nameplate rating of 15 kW would never occur and would not present a reliability hazard to the distribution system.[8] It should be noted that under distribution system fault conditions PCS or other export controls may not act in time to reduce fault currents. Utilities should continue to use rated fault current to evaluate protection impacts unless the export controls manufacturer provides test data proving that fault currents can be controlled.

b. The amount of inadvertent export potential (maximum 200% of export limit) is not dangerous to conductors.

The potential for distribution system safety and reliability impacts from IE events can be characterized by way of example. A possible, though unlikely, scenario for an individual IE event would be for a single system or group of systems to export 200% the current rating of the conductor. As described in the following example, this is not a safety or reliability concern as this is well within the capabilities of conductors.

A conductor should be rated for at least the maximum load power, which we will call 1X. So, the circuit has a current-carrying capacity of no less than 1X, and a maximum load of 1X. Assume that all load is served by a DER coupled with an energy storage system ("ESS"), such that either the generator or ESS (or in combination) can serve the whole load at any given time. Thus, the generator is sized for an output power of no less than 1X, and the ESS is also sized no less than 1X. An export limit for the DER is set, using a PCS, at 1X to remain within the circuit rating (which would equate to a hosting capacity of around 330% of export capacity compared to minimum load, assuming minimum load is 30% of maximum). Note that the likelihood of being able to export at 1X is unlikely as other system constraints like steady-state voltage would likely limit the export to a lower value. Also note that the NEC requires overcurrent protection of the conductors monitored by the PCS, so they remain protected.

In this example, in order to serve both the load as well as export up to the technical limit, the generator is sized at 2X and the ESS is also sized at 2X, for an aggregate nameplate rating of 4X (or 1,330% of minimum load). The ESS will not be discharging full power at the same time as the generator due to the lack of load, so at maximum the DER aggregate power is 2X (whether from either generation source alone or in concert). This also remains true if the ESS is charging, adding to the load. In this case the DER setpoint will depend on both the generator and ESS, and the combined output would remain 2X at maximum.

[8] The UL Certification Requirement Decision for Power Control Systems requires testing to ensure IE remains within limits for sudden increases in generation levels as well as for a drop in load.

Under a worst-case IE scenario, all 1X load would drop off instantaneously. This does not happen in the real world, as there is always some minimum load. The 2X steady-state operating level of the DER now flows through the 1X rated circuit until the control system brings the DER output down to 1X, back in line with the circuit's capacity. See Figure 1 below showing the current flow at the start of the IE event. While the output of the control system changes more akin to exponential decay, for our consideration we can simplify it to a linear response over a duration of 30 seconds. We can then consider this to mean an average of 1.5X current for 30 seconds, or similarly 2X for 15 seconds.[9] Note that many inverter-based PCS will have time responses much less than 30 seconds.

Emergency amperage ratings for conductors vary based on size, insulation and temperature, but typical examples are:

- Emergency/overload rating is at least 600% of the current rating for 30 seconds and at least 800% for 15 seconds.[10,11]
- Overload ratings for most conductors, including smaller insulated cables, are over 300% for 100 seconds and over 1000% for 10 seconds.[12]

Due to the ability of conductors to pass approximately 600% of rated current for 30 seconds, the 150% worst-case current for 30 seconds or 200% for 15 seconds should not be a reliability issue and leaves a conservative safety margin. Many conductors can withstand at least 150% or 200% rated current for 15 minutes or more. Even in the unthinkable scenario that worst-case IE events were triggered repeatedly one after another 30 times in a row, the conductor would not be damaged. Again, this example is at a very high level of penetration, assuming all DER is oversized compared to load and utilizing a PCS. DER interconnecting at lower levels of penetration would be subject to further study according to the R 460.946 procedures (460.946(4)(b) would not pass applications that would cause any reverse power on the line section).

Due to the diversity of loads and DER on any circuit, there is virtually no possibility that limited-export systems could inadvertently export all at the same time. Even so, the above example works similarly for a collection of diverse DER systems with worst-case inadvertent exports occurring at the same time, showing that thermal limits would not be exceeded in aggregate. See Figure 2 below showing current flow at the start of such an IE event.

Another potential mode for IE occurrence would be due to sharp fluctuations in generation. While PV systems do not increase power from 0% to 100% over very short periods of time under normal operation, we will use that as a boundary scenario. For this example, we assume that a PV system is sized at 4X (4 times the maximum load and 4 times the capacity of the circuit), and with a 1X export limit as in the example above.

[9] These simplifications are conservative, since the heating capability of overcurrent is dependent on the square of the current. E.g., for the 1.5X current case, the i^2 would be assumed as 2.25 A^2 for the full 30 seconds, rather than decreasing over time.
[10] Aluminum Electrical Conductor Handbook, Third Edition , The Aluminum Association (1989), https://www.aluminum.org/sites/default/files/AECD%20part1%20compressed.pdf.
[11] IEEE Std 242-2001 figure 9-17a.
[12] IEEE Std 242-2001 table 9-6.

This assumes the same penetration levels as in the first example. We will assume load is at zero, although this is never the case. If generation jumps from 0 to 4X instantaneously, we can consider the simplified IE event to be an average of 2.5X (250% of the circuit rating) for 30 seconds or 4X (400% of the circuit rating) for 15 seconds. This remains within the overload ratings mentioned above.

At a more practical level of penetration in today's terms, say where DER meets 100% of minimum load and could potentially pass through the fast track screens, there is even less worry about thermal issues. If all load was fully offset by DER, minimum load would be zero. Therefore, if all DER systems utilized a PCS, the export limit would be 0. Again, assume maximum load is 1X and the circuit rating is 1X. In this case the DER would be operating at 1X, with no current exporting. If all load drops off, the IE event will have a maximum current of 1X, or average of 0.5X over 30 seconds, all completely within the normal rating of the circuit.

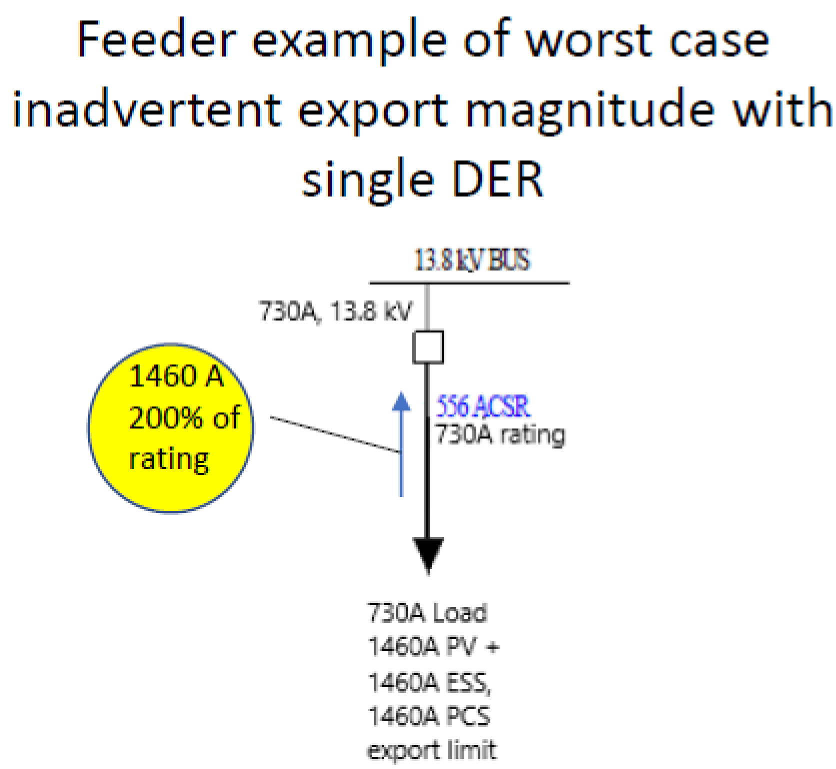

Figure 1 – Single DER with 1X rated circuit (1X = 730A in this example), and 1X rated load

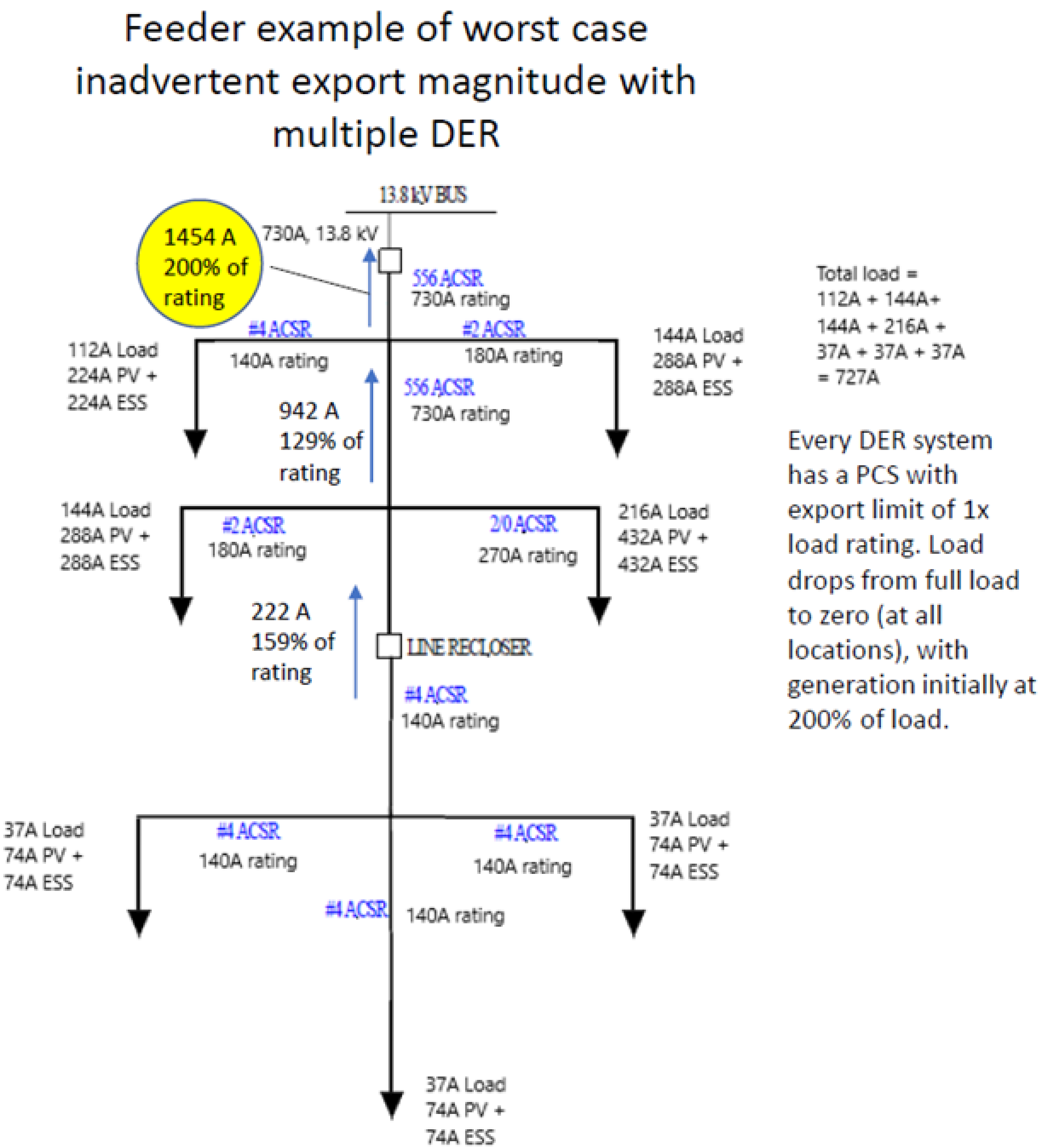

Figure 2 – Example feeder with multiple DER and 1X rated circuit (1X = 730A in this example) and 1X load

c. **Conclusion on conductor effects.**
Given the above analysis, I determine that the overloading of conductors due to IE events that the MIXDG rules would allow would not result in catastrophic damage to conductors.

d. The amount of inadvertent export potential is not catastrophic to transformers.

Contrary to the language of the Petition[13], overloading a transformer for a short period is not likely to result in fire except for very large overloads. The American National Standard ANSI C57.92-1981 IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA with 55 °C or 65 °C Average Winding Rise gives recommendations for loading transformers based on loss of life due to aging of the winding insulation. This aging which occurs under normal use is a function of time and temperature, though it can be exacerbated by overloading. According to the standard, normal daily loss of life for a transformer is 0.0369% at an average ambient temperature of 30 °C (86 °F). Lower ambient temperatures should give higher loading capability with no effect on transformer lifetime. The actual loading capabilities are determined based on a hottest spot temperature value. As noted in the standard[14]:

"Normal life expectancy will result from operating with a continuous hottest-spot conductor temperature of 110 °C (or equivalent variable temperature with 120 °C maximum) in any 24 h period."

"Transformers may be operated above 110 °C hottest-spot temperature for short periods provided they are operated for much longer periods at temperatures below 110 °C."

Transformer temperature rise requires some appreciable duration of loading to significantly raise the internal temperature, but is also dependent on cooling and ambient temperature. Table 3(d)[15] in the standard gives the capability for normal and moderate sacrifice of life for 65 °C rise, self-cooled (OA) and water-cooled (OW) transformers with equivalent load before peak load equaling 100% of the nameplate rating. It would be a conservative assumption to use 100% preloading and then assume an IE event of 200% of the transformer rating. This would be akin to a DER system(s) exporting at its maximum technical interconnection limit (the transformer rating) all day long and then all load dropping off at once to create the IE event. Table 3(d) shows that a transformer under these preloading[16] conditions can withstand 30 minutes of 200% overloading in a day to equate to a 0.25% loss of life, and the top oil temperature would reach 98 °C. Top oil temperature would need to approach 145 °C to create a risk of sudden ignition and explosion[17]. That would account for 60 IE events per day if the events were actually 30 seconds in duration and at the rating of the transformer for the duration, which is an unnecessarily conservative assumption per the discussion in section II.b of this memo. That level of loss of life equates to 162 hours over the 65,000 hour normal expected lifetime of the transformer. This effect is far from a catastrophic fire.

[13] Petition for Rehearing, p. 8
[14] IEEE C57.92 at p. 39 - 40
[15] IEEE C57.92 at p. 22
[16] Including a 30 °C ambient temperature
[17] P.K. Sen et al., Transformer Overloading and Assessment of Loss-of-Life for Liquid-Filled Transformers Final Report, Power Systems Engineering Research Center, p. 15 (February 2011), https://pserc.wisc.edu/wp-content/uploads/sites/755/2018/08/T-25_Final-Report_Feb-2011.pdf

e. Conclusion on transformer effects.
Given the above analysis, I determine that the overloading of transformers due to IE events that the MIXDG rules would allow would not result in catastrophic damage to transformers.

III. The BATRIES Toolkit provides learnings on power quality effects of inadvertent export and suggestions for eligibility limits and screening.

Learnings from the BATRIES Toolkit note that power quality impacts of inadvertent export events are likely to be minimal especially for smaller systems, and those impacts can be screened for with the addition of an IE voltage change screen. Modeling and simulation conducted for the BATRIES project indicate that power quality effects of IE are likely to be minimal except for larger systems under certain circumstances. To screen for this effect, an IE voltage change screen was derived and large systems that would have an effect can be effectively screened regardless of eligibility limits being based on the limited-export power.

a. Chapter V of the BATRIES Toolkit notes the potential worst-case conditions for power quality effects of inadvertent export.

Chapter V of the BATRIES Toolkit describes modeling and simulation for urban and rural feeders and the penetrations at which coincident occurrences of IE could introduce power quality (voltage) issues. These coincident scenarios are worst-case rather than real-world. The key findings of this chapter state[18]:

"These response times support the assertion that thermal impacts are unlikely to be a limiting factor for inadvertent export because both their level (110% maximum) and duration (typically 2-10 seconds) are below any known thresholds for concern."

Based on this modeling, a screen for voltage-based power quality interactions was devised and is presented in Chapter IV. It is presumed that this screen would catch thermal effects as well, as voltage impacts are likely to occur before thermal issues arise.[19]

b. Chapter IV of the BATRIES Toolkit bases some screening or study on the limited-export value, and introduces a new inadvertent export screen to screen for voltage impacts of inadvertent export.

The BATRIES Toolkit defines the term Export Capacity, which has a similar meaning to "ongoing operating capacity" of R 460.901(b). Chapter IV notes that it is reasonable to assess the steady-state export, and thus the limited-export value, in the penetration and transformer screens.[20]

However, as noted by the BATRIES Toolkit[21]:

[18] BATRIES Toolkit, p. 92
[19] BATRIES Toolkit, p. 64
[20] BATRIES Toolkit, p. 62 – 66
[21] BATRIES Toolkit, p. 63

"The 15% screen is used as a proxy for reviewing voltage and other system effects. Any steady-state voltage rise due to reverse power flow would continue to be effectively evaluated under the 15% screen since the exported power that could cause reverse flow would still be accounted for. However, nonexporting DER capacity could also potentially introduce voltage changes due to inadvertent export events. As these short-term voltage effects would be dependent on only the non-exporting portion of the Nameplate Rating, the revisions to the 15% screen could mean that there is a possibility that these voltage changes would not be effectively screened. The non-exporting portion is the Nameplate Rating minus the Export Capacity."

Thus, an IE screen was devised to catch any possible voltage changes greater than 3%[22], which is a conservative value based on IEEE 1547-2018 requirements of subclause 7.2.2.[23] Note that this screen considers load equal to the nameplate rating at the DER site to turn off at once. This is a conservative assumption. As noted in section II.a of this memo, the nameplate rating will not present itself at the DER terminals if site load is lower. The BATRIES Toolkit limits the application of this screen to systems where this conservative estimate of IE power is less than 250 kVA.

The Toolkit notes[24]:

"To limit the need to apply this screen to systems where there is little chance of voltage impact, the project team completed a review of the calculation for a large selection of feeders. No change lower than 298 kW triggered a calculation of more than 3% at the end of an "average" 12 kilovolts (kV) medium length feeder, and detailed calculations showed a maximum change of 368 kW. For a longer 4.2 kV feeder, the calculation was maintained within the limit up to 413 kW, with detailed calculations finding a maximum change of 574 kW. Therefore, it is reasonable to assume compliance without the need of running the calculation for systems with a non-exporting capacity below 250 kW."

While the limited applicability of this screen may allow it to be used in initial review screens, similar evaluations for power quality (e.g., evaluation of voltage change due to loss of generation) are typically only performed in supplemental review. Applying this screen should eliminate the instances where unintended voltage effects of IE are discovered in the field.

c. Chapter IV of the BATRIES Toolkit bases eligibility limits on the export power value.

As noted in the BATRIES Toolkit[25]:

"The eligibility limit does not take the place of the screens and thus should only be used to sort out projects that are very unlikely to pass the screens.

[22] BATRIES Toolkit, p. 63 – 65
[23] IEEE Std 1547-2018 IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, p. 61
[24] BATRIES Toolkit, p. 65
[25] BATRIES Toolkit, p. 61

Fast Track eligibility should be modified so that it is evaluated on the basis of the project's Export Capacity and not the Nameplate Rating of the project."

d. Conclusion

Taken together with all the Chapter IV screens, the eligibility limit based on the limited-export value would still allow proper screening of impacts from limited-export systems. While missing the inadvertent export screen, Michigan R 460 hews fairly closely to the concepts introduced by the BATRIES Toolkit. Some states (such as Illinois in its Rule 466) do not yet introduce the inadvertent export screen, but we encourage it be discussed by states innovating interconnection rules to be more suitable for storage systems.

IV. Overall Conclusion

As detailed in sections I – III of this memo, the Petitioners' safety and reliability concerns around the allowance for certified Power Control Systems (PCS) to limit export, the effects of IE on conductors and transformers, and the ramifications of fast track eligibility limits and screens being based on the limited-export value appear to be unfounded. Given that the MIXDG rules generally follow emerging best practice, IREC encourages those rules to move toward implementation, even if some changes are made as a result of the rehearing. The Public Service Commission, utilities and stakeholders can rest assured that safety or reliability issues will not likely arise due to application of these rules.

Sincerely,

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STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to promulgate rules governing electric interconnection and distributed generation and to rescind legacy interconnection and net metering rules.	))))))	Case U-20890

COMMENTS OF THE MICHIGAN ELECTRIC AND GAS ASSOCIATION

Pursuant to the Commission's May 26, 2022 Order establishing a second public hearing for the administrative rules governing Michigan's electric interconnection and distributed generation programs, the Michigan Electric and Gas Association[1] ("MEGA" or "the Association") submits these comments in response to the Commission's request for public comment regarding the draft rules.

I. Procedural History

The Commission in its September 9, 2021 order provided a draft update to the Michigan Interconnection for Distributed Generation (MIXDG) rules, setting a public hearing for October 20, 2021 and allowing for submission of written comments until November 1, 2021. On March 17, 2022, the Commission adopted the rules, as revised, and referred the rules to the Michigan Office of Administrative Hearings and Rules and the Legislative Service Bureau for formal approval and transmission to the Joint Committee on Administrative Rules.

On April 14, 2022, Consumers Energy Company (Consumers) and DTE Electric Company

[1] The MEGA member companies are investor-owned natural gas and electric utilities with fewer than 500,000 customers in the state of Michigan, and include: Alpena Power, Citizens Gas Fuel Company, Indiana Michigan Power, Michigan Gas Utilities, Northern States Power Company – Wisconsin, SEMCO Energy Gas Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company.

(DTE Electric) (together, petitioners) filed a Joint Petition for rehearing of the Commission's March 17, 2022 Order (Joint Petition) pursuant to Mich Admin Code, R 792.10437 (Rule 437).

On May 4, 2022, Indiana Michigan Power Company (I&M), Michigan Electric and Gas Association (MEGA), and Michigan Electric Cooperative Association (MECA) filed answers to the Joint Petition for rehearing. On May 5, 2022, the Environmental Law and Policy Center, Ecology Center, and Vote Solar (together, the Clean Energy Organizations or CEOs) filed an answer to the Joint Petition.

On May 12, 2022, the Commission granted the Joint Petition for rehearing and at its May 26, 2022 hearing set the schedule for the public hearing and submission of written comments based on the draft rules included in the May 26, 2022 Order.

II. Introductory Comments

MEGA thanks the Commission for providing this additional opportunity for public comment on the proposed rules. As the Commission is aware, these rules have far-reaching effects on customer demand, interactions between utilities and their customers, and the safe, reliable operation of the grid.

The Association supported the Joint Petition because its members agreed with certain concerns being expressed by the Joint Petitioners, particularly those related to safety. Further, because our members continue to evaluate their procedures for interconnecting customer-owned distributed generation systems, new issues have arisen that the Association members seek to raise for the Commission's consideration. MEGA's membership is comprised of smaller utilities, and these complex rules have required significant time to develop the draft procedures presented to the Staff Workgroup. Each Association member will continue to refine their individual proposals for submission once the final rules in this docket are adopted.

The opportunity for all parties to review the final draft rules prior to submission to the Office of Administrative Hearings and Rules will benefit stakeholders later in the process as utilities develop their procedures for evaluating potential impacts of interconnecting customer-owned resources to the utility's distribution system.

MEGA members have expressed concerns that the changes being proposed by the draft rules may not adequately resolve certain safety and/or reliability issues that inherently exist with larger, complex customer-owned systems (despite the additional time afforded our members under proposed Rule 908). The Association's members believe these matters are worthy of reconsideration by the Commission.

MEGA will summarize its previous comments that remain applicable to the current draft rules (Section III), discuss new issues that have been identified by its members as they continue to review the rules to determine how they will be implemented (Section IV), and address specific rule comments under Section V.

III. Summary of Previous MEGA Comments

First and foremost, MEGA would like to thank the Commission for recognizing the significant impact the rules and processes contained therein have on utilities and the relationship they maintain with their customers, as the Association noted in its initial comments (MEGA Comments Pages 2-3). MEGA welcomes the addition of Rule 908 (460.908) that provides additional time for the smaller utilities to review and process their customers' requests for interconnection while ensuring reliability and safety are maintained. While this additional time will be beneficial to the Association's members, there are some remaining concerns regarding safety and reliability that are addressed below in Section IV.

As noted in their previous comments (Page 10), MEGA members remain concerned about the costs of implementing the rules. Many of these rules will require additional investments that are not currently contemplated by the Association's members, whether that's potential information technology upgrades or additional staff required to implement the requirements and processes that are set forth in these rules. As an example, some of our utilities will have to create new systems to manage this complex process, while others will have to modify existing systems. In either case, the cost for establishing the new systems and upgrades will be assigned to and recovered from the member's Michigan-based customers.

MEGA is disappointed in the fee cap reductions for impact studies. In our proposed draft filings in the stakeholder workgroups, it was noted that our members will be seeking higher fee caps to ensure adequate cost recovery in their individual cases. MEGA did not lower the fee caps as adopted by the Commission in its final rules for the System Impact Study or Facilities Study to reflect that there will be actual costs that will exceed the proposed caps in the final rules.

IV. Additional Comments Pursuant to Draft Rules Adopted May 26, 2022

The revisions the Commission proposed in the new draft rules have generated additional concerns for MEGA members. Association members are concerned about safety and reliability, and some of the changes could have adverse impacts. The Joint Petition outlined several concerns that MEGA members share, as discussed below.

MEGA agrees with the Joint Petitioners' assessment of the rule promulgation authority granted to the Commission, the scope of which is further defined by MCL 460.1173. The statute's clear focus on maintaining safety and reliability of the grid provides strong guidance that "Michigan law reserves to electric utilities the right to test and approve all proposed interconnections to their electrical systems." (Joint Petitioners, Page 7). MEGA members have identified some potential issues for the consideration of the Commission.

First, there has been an increase in the number of customers that are proposing to install more generation capacity than is currently allowed under the statute for each system level. These customers have typically purchased "turn-key" installations from an electrician or solar installation contractor and are relying on them to develop and submit the documentation that is required under the Rules. When the issue is raised by the utility during its review of the customer's application, the customer's electrician or solar installation contractor has attempted to utilize the inverter to limit the amount of the export to the utility's distribution system to stay under the statutory cap. This is generally accomplished via programming of the inverter (in the field).

These types of arrangements create both a safety and reliability issue because the inverter can be modified by the customer or its contractor AFTER the installation, inspection, and approval by the utility. This scenario creates a potential safety and or reliability concern without the utility's knowledge. The utility is now tasked with inspecting numerous interconnections to ensure that the customer, developer, or third party has not altered the software or modified the system in a manner that adversely affects the safe and reliable operation of grid. Smaller utilities, like MEGA members, may not have the ability to inspect each the hardware or software settings for each interconnected inverter.

Lastly, it has been the experience of MEGA members that some customers have modified and or added additional equipment that substantially alters the characteristics of their installation after inspection and approval by the utility. This scenario also presents potential safety and or system reliability concerns whenever the utility has not been afforded an opportunity to fully evaluate the customer's modifications prospectively. Consistent with statute, MEGA members believe there is a strong need for requiring the customer to install disconnecting devices that provide the utility's staff with the ability to visibly confirm all customer-owned sources of energy have been disconnected from the distribution system. This safety precaution helps to ensure the safety of utility workers and the general public.

V. Specific Rule Comments

Part 1. General Provisions

Rule 460.1a(cc) Definitions; A-I and Rules 460.952 and 460.956 Alternative Process

MEGA had previously expressed concern about the overlap between the Regional Transmission Operator (RTO) methodology where MEGA members provide consolidated Distribution Impact System reports that include components of the Feasibility, Impact and Facilities, Studies.

The Association appreciates the Commission's adopting in the draft rules an alternative process (R 460.952 and R 460.956) to create flexibility and reduce duplication of process with the RTO.

Rules 460.901a(bb), 460.901a(gg), and 460.901b(x) Capacity Definitions

The definition of Aggregated Capacity R 460.901(d) states "aggregated ongoing operating capacities of all DERs across multiple points of common coupling" which seems to run counter to the definition of "Generating Capacity" in 460.901(gg). MEGA suggests the Commission should clarify that this definition means the sum of total nameplate capacity for all DERs without the inclusion of export limiting technologies.

The definition of "Generating Capacity" R 460.901(gg) also includes the language; "except that where this capacity is limited by any of the methods of limiting electrical export, generating capacity shall be the net capacity as limited though the use of such methods not including inadvertent export." This language seems appropriate for the definition of "Export Capacity," but we feel generation capacity should include the total nameplate capacity of a DER(s) so that utilities have full visibility into the assets being installed behind a single metering point. This would prevent developers from "hiding" capacity (i.e., a 20MW solar array with 15MW battery storage system appearing as 5MW to qualify for fast-track review).

Rule 460.1b(s) Nameplate Capacity

MEGA suggested that the Nameplate Rating should also include Ah and kWh ratings for Energy Storage. The Commission declined to modify the definition and instead added kWh (for storage) to the nameplate capacity description in R 460.930(2)(e).

The Association appreciates the Commission's action on this issue.

Rule 460.908 Timelines for electric utilities serving fewer than 1,000,000 in-state customers. (Previous Rule 908 – Appointment of Experts)

Regarding the former Rule 908, MEGA again appreciates the Commission's efforts to streamline the rules and remove burdensome requirements and looks forward to continuing to work with Staff in this regard.

Regarding the new Rule 908 granting additional time for smaller utilities to evaluate and work with their customers on interconnections, the Association members thank the Commission for recognizing the concerns expressed by the smaller utilities. We believe this extra time will be beneficial, particularly as the companies navigate through implementation of these new rules. Further, we believe the additional time will enable increase the ability of the smaller teams at each utility to evaluate interconnection applications and systems.

Part 2. Interconnection Standards

Rule 460.914 Transition non-study group, Rule 460.916 Legacy applications, Rule 460.918 Transition batch study process, Rule 460.918(8)(b) Transition batch study process, Rule 460.918(10) Transition batch study process, Rule 460.918(15) Transition batch study process

While not specifically addressing Association concerns relating to the transition batch process, in removing the rules in their entirety, MEGA's concerns have been addressed. The Association appreciates the Commission's action on this issue to provide greater clarity to both utilities and customers.

Rules 460.926 and 460.928 Initial fees and **Fee and fee cap modifications**

While MEGA understands the benefits of set fees across the board for interconnections, MEGA disagrees with the Commission's reductions imposed on the fee caps for the fast track, system impact study, and facilities study. Association members have experienced widely varying costs associated with studies in applications they have received thus far, as many members are contracting third parties to conduct these studies. Further, MEGA members remain concerned about cost-shifting from the cost-causer (applicant) to other ratepayers in the applicable customer class of the applicant.

While MEGA appreciates that a waiver process has been included in the rules, members are concerned that a waiver process creates two issues. First, the Commission is arbitrarily capping fees from actual costs that are to be incurred by the utility to process the application. In our initial draft process documents submitted to staff in the stakeholder workgroup, we assume higher fees to be proposed by MEGA members to reflect that. Second, MEGA members believe that because cost recovery is limited to actual costs, caps are unnecessary.

MEGA requests that, at a minimum, the Commission revert to the previous fees for the three above studies. Alternatively, the Commission could consider a process for study fees that sets a deposit amount or requires the utility to provide a good-faith estimate that is later trued-up once all studies are completed. These trued-up costs would have to be paid prior to moving forward in the application process.

This would provide transparency to the applicant on the potential costs for the studies, and ensure full cost recovery of the studies, preventing subsidization of the applicant by other ratepayers.

Rule 460.942 Non-export track review

Association members have expressed concern that the utility may not be informed of potential load offsets in these types of applications. Noting that the rule appears to give discretion to utility in setting some screening criteria, MEGA nonetheless suggest adding a requirement that, at a minimum, the project's nameplate rating must be included in the application and further, that the utility retains the right to determine the load offset. These are critical specifications of the proposed system that should be included in every application so that the proposed system can be properly reviewed.

Rule 460.944 Fast track applicability, Rule 460.946 Fast track; initial review

MEGA has significant concerns with the inability to require additional screens being specifically allowed in the rules. MEGA members have concerns related to safety and reliability. With technology shifting at an increasingly rapid pace, the ability of utilities to respond to the changing dynamics of customer interconnect requests is an important facet of ensuring safety and reliability. Association members believe additional screens would assist in proper evaluation of some of the concerns outlined above, specifically related to situations where overbuilt systems are being applied for interconnect.

In addition, under Rule 460.944 Level 1 - 5 DERs may receive fast track approval and provide for "use of an energy storage device so the export of power meets the requirements of level 1, level 2, level 3, level 4 or level 5 as large as 5 MWac." It remains unclear to MEGA members whether a DER larger than 5MW would qualify for fast-track review if energy storage or some other export limiting technology (that may have its own safety considerations that would need to be independently evaluated) is used to reduce the export capacity to 5MW or less.

Rule 460.984 Modifications to the DER

MEGA appreciates the Commission's commitment to safety by revising the rules to remind applicants that they should proceed with material modifications pursuant to an executed Interconnection Agreement, as experience (noted above) has indicated that this is a growing problem and is generating concern amongst members. As noted earlier, the onus is on the utility to continually inspect equipment that is not utility-owned to ensure safety and reliability, and here, to ensure that customers are not violating their interconnection agreement.

R 460.986 Insurance.

MEGA appreciates the flexibility the rules provide to utilities to ensure that there are adequate insurance policies. While the Association believes this flexibility should extend to all Levels, the requirements for larger projects under Levels 3 – 5 are appreciated.

R 460.988 Easements and rights-of-way.

MEGA members have concerns that the requirement the utility obtain easements for line extensions to serve a DER customer is untenable. After reviewing and considering the proposed changes to Michigan's Rule 460.988, which would require utilities to acquire easements at the request of private entity "applicants" for tie-ins from generating facilities to the larger electric "grid" ("interconnections"), but also requires the applicants to pay for the "cost" of such acquisitions, MEGA members have identified the following four concerns and considerations that MEGA members would like the Commission to consider with regard to the proposed Rule changes:

Condemnation Rights and Responsibilities

A potentially significant concern for utilities regarding the proposed change to Rule 460.988 and the new requirement that utilities "provide and obtain" easements and rights-of-way for interconnections is that utilities might be required to exercise their condemnation powers to acquire such easements, and in doing so, might be subject to successful objections from property owners during the condemnation process that might ultimately prevent utilities from acquiring the easements needed for the interconnections. In Michigan, electric utilities fall under the Uniform Condemnation Procedures Act (UCPA) (PA 87 of 1980). If a property owner raises an objection during condemnation to a private utility's need or necessity for a proposed taking of property (in this case, an easement), and if the taking is not pursuant to a Certificate of Public Convenience and Necessity, the trial court is given broad discretion to determine whether the requisite "need" exists for the taking. This presents an opportunity for the trial court to scrutinize the route designated for the line in question, and the location of the easement to be acquired. If the trial court determines that an alternative route for the line (and thus an alternative location for the easement) exists and would be preferable/less burdensome/more reasonable, the court could sustain the property owner's objection to the condemnation, which would prevent the utility from acquiring the easement through condemnation.

This is of concern to utilities because, in cases of interconnections, the utility would not have the opportunity to choose the location of the generating facilities, and therefore the line route for the tie-in (that would necessarily run between the generating facility and the utility's substation/tie-in point) would be generally predetermined by the applicant requesting the interconnection – not the utility. This would leave utilities in the unfortunate position of defending a line route or siting decision in a condemnation of an easement for the interconnection which the utility did not choose and likely will not have an opportunity to vet. If the applicant chooses a non-ideal location for the generating facility, property owners whose land is condemned for easements for the interconnection may be successful in challenging the line route and the need for the easements being condemned, and the utility would be unable to acquire the easement through condemnation.

Not only does the possibility of a successful objection in this regard put the utility in the unfortunate position of defending siting decisions which it did not make, but it also creates the opportunity for utilities to ultimately be unable to fulfill their obligation under Rule 460.988 to acquire the easements needed for an interconnection. It also raises the question of who will incur the costs of an unsuccessful condemnation, given that the utility will initially incur those costs but Rule 460.988 could be interpreted as only requiring the interconnection applicant to reimburse the utility for the costs of successfully acquiring the easements for the interconnection – and not necessarily for the costs of an unsuccessful attempt to acquire the necessary easements.

<u>Cost Recovery and Transparency</u>

Utilities are also concerned that the "costs" of obtaining easements under Rule 460.988, which the applicant is required to pay, are not defined. Utilities will presumably be required to initially incur all of the substantial costs of acquiring/attempting to acquire the easements for the interconnection (including legal and court fees, costs of personnel to negotiate acquisitions, title and survey costs and the actual acquisition costs) and to seek reimbursement from the applicant. However, since the "costs" to be reimbursed do not appear to be defined under the Rules, utilities may be required to expend additional sums to establish that they are entitled to reimbursement from the applicants for all the substantial costs incurred by the utilities in obtaining/attempting to obtain the easements for the interconnection. If all expenses incurred by the utility on pursuing the needed easements are not recouped by the utility from the applicants, there is the possibility that the utility's rate base will have to absorb the additional costs.

Utilities might also be concerned that their ability to successfully acquire easements outside of condemnation (through informal negotiations with property owners either before or during condemnation proceedings) may be hindered by the fact that the utility is not ultimately responsible for the costs of the acquisition. Because the applicant is ultimately responsible for the costs of the easement acquisitions, the applicant may seek to restrict the utility's ability to informally resolve acquisitions by limiting the compensation that the utility is authorized to offer property owners to resolve the easement acquisition.

Assignment of Acquired Easements and Liability Concerns

Another concern of utilities is that their ability to assign the easements back to the applicants after the easements are acquired may be restricted if the easements are acquired through condemnation. Property owners who are aware that the utility is only exercising its powers of eminent domain to acquire easements for the applicant's interconnection may object to the taking during the condemnation by arguing that the taking is essentially an impermissible taking for a private purpose if the utility intends to assign the easement to a private entity (the applicant) immediately following its acquisition. To avoid this potentially successful objection, utilities may be forced to maintain their ownership of the easements for the interconnection that are acquired through condemnation, even though the utility may not own or operate any of the tie-in facilities that will occupy the easement.

Unfortunately, ownership of the interconnection easements may subject the utilities to additional liabilities and obligations in regard to maintaining the easements. In particular, easement holders are required to maintain their easement areas in a safe condition, Morrow v Boldt, 203 Mich App 324, 330; 512 NW2d 83, 86 (1994). If utilities are precluded from assigning the easements to the applicants in order to avoid a successful objection to the taking if the easements are acquired by condemnation, then this ongoing maintenance obligation would fall upon utilities in regard to interconnection easements, and utilities would be forced to incur ongoing costs and liabilities regarding their maintenance of the easements. These costs would ultimately be borne by the ratepayers of the utility, essentially subsidizing a private entities' assets with no benefit to the ratepayers.

Timing of Acquisition

Utilities are tasked under the proposed rules to perform several tasks on behalf of the customer/applicant, including acquiring necessary easements for the project Acquisition of easements, depending on the nature and need of easement necessary for the project may result in timing issues with the customer's/applicant's application. Utilities may have difficulties in securing these easements delaying a project (outlined above). Smaller utilities have limited resources (which the Commission has recognized by affording additional time for processing applications in proposed R 460.908), but easements could result in additional time and cost that affect other areas of the utility service. Utilities must remain focused on their core mission to deliver safe and reliable service to all customers. Easement acquisition may have elements outside the utility's control that delay interconnection and or could impact core utility services if staffing resources need to be reallocated to meet deadlines in the rules.

VI. Conclusion

MEGA appreciates the Commission's willingness to reopen the comments in the docket for these rules and appreciates the opportunity to provide additional feedback on the changes made. The Association again thanks the Commission for additional time to work with applicants on these agreements.

The Association asks the Commission to consider its comments, particularly relating to control of equipment, safety, and reliability as well as the fee structure and easements outlined above.

Sincerely,

Dated: June 27, 2022

Daniel Dundas
President
Michigan Electric and Gas Association