(B) The commission may take into account any change in business risk to the utility resulting from establishment, continuation, or modification of the ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(C) In determining which environmental cost components to include in an ECRM, the commission will consider, but is not limited to only considering, the magnitude of the costs, the ability of the utility to manage the costs, the incentive provided to the utility as a result of the inclusion or exclusion of the cost, and the extent to which the cost is related to environmental compliance.

(D) The commission may, in its discretion, determine what portion of prudently incurred environmental costs may be recovered in an ECRM and what portion shall be recovered in base rates.

(E) Any party to the general rate proceeding may oppose the establishment, continuation, or modification of an ECRM and/or may propose alternative ECRMs for the commission's consideration, including but not limited to modifications to the electric utility's proposed ECRM.

(F) The ECRM shall be based on known and measurable environmental costs that have been incurred by the electric utility.

(G) If an ECRM is approved, the commission shall determine the base environmental revenue requirement.

(H) If costs are requested to be recovered through the ECRM and the revenue to be collected in the ECRM rate schedules exceeds two and one-half percent (2.5%) of the electric utility's Missouri annual gross jurisdictional revenues, the electric utility cannot subsequently request that any cost identified as an environmental cost be recovered through a fuel rate adjustment mechanism.

(I) The electric utility shall include in its initial notice to customers regarding the general rate case, a commission approved description of how the costs passed through the proposed ECRM requested shall be applied to monthly bills.

(J) The electric utility shall meet the filing requirements in 4 CSR 240-3.162(2), in conjunction with an application to establish an ECRM, and 4 CSR 240-3.162(3), in conjunction with an application to continue or modify an ECRM.

(3) Application for Discontinuation of an ECRM. The commission shall allow or require the rate schedules that define and implement an ECRM to be discontinued and withdrawn only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that affect the cost or overall rates and charges of the petitioning electric utility.

(A) Any party to the general rate proceeding may oppose the discontinuation of an ECRM on the grounds that the electric utility is currently experiencing, or in the next four (4) years is likely to experience, declining costs or on any other grounds that would result in a detriment to the public interest. If the commission finds that the electric utility is seeking to discontinue the ECRM under these circumstances, the commission shall not permit the ECRM to be discontinued, and shall order its continuation or modification. To continue or modify the ECRM under such circumstances, the commission must find that it provides the electric utility with a sufficient opportunity to earn a fair rate of return on equity.

(B) The commission may take into account any change in business risk to the corporation resulting from discontinuance of the ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(C) The electric utility shall include, in its initial notice to customers regarding the general rate case, a commission approved description of why it believes the ECRM should be discontinued.

(D) Subsections (2)(C) through (2)(H) shall apply to any proposal for continuation or modification.

(E) The electric utility shall meet the filing requirements in 4 CSR 240-3.162(4).

(4) Periodic Adjustments of ECRMs. If an electric utility files proposed rate schedules to adjust its ECRM rates between general rate proceedings, the staff shall examine and analyze the information filed by the electric utility in accordance with 4 CSR 240-3.162 and additional information obtained through discovery, if any, to determine if the proposed adjustment to the ECRM is in accordance with the provisions of this rule, section 386.266, RSMo, and the ECRM established in the most recent general rate proceeding. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff schedules to adjust its ECRM rates. If the ECRM rate adjustment is in accordance with the provisions of this rule, section 386.266, RSMo, and the ECRM established in the most recent general rate proceeding, the commission shall either issue an interim rate adjustment order approving the tariff schedules and the ECRM rate adjustments within sixty (60) days of the electric utility's filing or, if no such order is issued, the tariff schedules and the ECRM rate adjustments shall take effect sixty (60) days after the tariff schedules were filed. If the ECRM rate adjustment is not in accordance with the provisions of this rule, section 386.266, RSMo, or the ECRM established in the most recent rate proceeding, the commission shall reject the proposed rate schedules within sixty (60) days of the electric utility's filing and may instead order implementation of an appropriate interim rate schedule(s).

(A) The periodic adjustments shall be limited to the expense items and the capital projects that are used to determine the environmental revenue requirement in the previous general rate proceeding and those investments or expenses necessary to comply with the electric utility's Environmental Compliance Plan for the period the ECRM is in effect.

1. The costs for capital projects will be eligible for recovery via a periodic adjustment so long as the capital cost of the item when it is placed into service is greater than or equal to the original cost (as of the time that such least costly capital item was placed into service) of the least costly capital item that was included in the environmental revenue requirement (to be determined as provided in 4 CSR 240-20.091(1)(D)); and

2. Waivers from the limitations in this subsection (4)(A) may be sought for capital projects placed into service that could not have been anticipated in the previous general rate proceeding or that do not meet the threshold provided for in the immediately preceding sentence.

(B) The periodic adjustment shall reflect a comprehensive measurement of both increases and decreases to the environmental revenue requirement established in the prior general rate proceeding plus the additional environmental costs incurred since the prior rate proceeding.

(C) Any periodic adjustment made to ECRM rate schedules shall not generate an annual amount of general revenue that exceeds two and one-half percent (2.5%) of the electric utility's Missouri gross jurisdictional revenues established in the electric utility's most recent general rate proceeding.

1. Missouri gross jurisdictional revenues shall be the amount established in the electric utility's most recent general rate proceeding and exclude gross receipts tax, sales tax, and other similar pass-through taxes not included in tariffed rates for regulated services;

2. The electric utility shall be permitted to collect any applicable gross receipts tax,

sales tax, or other similar pass-through taxes, and such taxes shall not be counted against the two and one-half percent (2.5%) rate adjustment cap; and

3. Any environmental costs, to the extent addressed by the ECRM, not recovered as a result of the two and one-half percent (2.5%) limitation on rate adjustments may be deferred, at a carrying cost each month equal to the utility's net of tax cost of capital, for recovery in a subsequent year or in the utility's next general rate proceeding.

(D) An electric utility with an ECRM shall file one (1) mandatory adjustment to its ECRM in each true-up year coinciding with the true-up of its ECRM. It may also file one (1) additional adjustment to its ECRM within a true-up year with the timing and number of such additional filings to be determined in the general rate proceeding establishing the ECRM and in general rate proceedings thereafter.

(E) The electric utility must be current on its submission of its Surveillance Monitoring Reports as required in section (9) and its monthly reporting requirements as required by 4 CSR 240-3.162(5) in order for the commission to process the electric utility's requested ECRM adjustment increasing rates.

(F) If the staff, Office of the Public Counsel (OPC), or other party who receives the information that the electric utility is required to submit in 4 CSR 240-3.162 and as ordered by the commission in a previous proceeding, believes that the information required to be submitted pursuant to 4 CSR 240-3.162 and the commission order establishing the ECRM has not been submitted in compliance with that rule, it shall notify the electric utility within ten (10) days of the electric utility's filing of an application or tariff schedules to adjust the ECRM rates and identify the information required. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was in compliance with the requirements of 4 CSR 240-3.162, within ten (10) days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel, the processing time line for the adjustment to increase ECRM rates shall be suspended. If the commission then issues an order requiring the information be provided, the time necessary for the information to be provided shall further extend the processing time line for the adjustment to increase ECRM rates. For good cause shown the commission may further suspend this timeline. Any delay in providing sufficient information in compliance with 4 CSR 240-3.162 in a request to decrease ECRM rates shall not alter the processing timeline.

(5) True-ups of an ECRM. An electric utility that files for an ECRM shall include in its tariff schedules and application, if filed in addition to tariff schedules, provision for true-ups on at least an annual basis which shall accurately and appropriately remedy any over-collection or under-collection through subsequent rate adjustments or refunds.

(A) The subsequent true-up rate adjustments or refunds shall include interest at the electric utility's short-term borrowing rate. The interest rate on accumulated ECRM under-collections or over-collections shall be calculated on a monthly basis for each month the ECRM rate is in effect, equal to the weighted average interest rate paid by the electric utility on short-term debt for that calendar month. This rate shall then be applied to a simple average of the same month's beginning and ending cumulative ECRM over-collection or under-collection balance. Each month's accumulated interest shall be included in the ECRM over-collection or under-collection balances on an ongoing basis.

(B) The true-up adjustment shall be the difference between the revenue collected and the revenue authorized for collection during the true-up period and billed revenues associated with the ECRM during the true-up period.

(C) The electric utility must be current on its submission of its Surveillance Monitoring Reports as required in section (9) and its monthly reporting requirements as required by 4 CSR 240-3.162(5) at the time that it files its application for a true-up of its ECRM in order for the commission to process the electric utility's requested annual true-up of any under-collection.

(D) The staff shall examine and analyze the information filed by the electric utility pursuant to 4 CSR 240-3.162 and additional information obtained through discovery, to determine whether the true-up is in accordance with the provisions of this rule, section 386.266, RSMo, and the ECRM established in the electric utility's most recent general rate proceeding. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff schedules for a true-up. The commission shall either issue an order deciding the true-up within sixty (60) days of the electric utility's filing, suspend the timeline of the true-up in order to receive additional evidence and hold a hearing if needed, or, if no such order is issued, the tariff schedules and the ECRM rate adjustments shall take effect by operation of law sixty (60) days after the electric utility's filing.

1. If the staff, OPC, or other party who receives the information that the electric utility is required to submit in 4 CSR 240-3.162 and, as ordered by the commission in a previous proceeding, believes the information that is required to be submitted pursuant to 4 CSR 240-3.162 and the commission order establishing the ECRM has not been submitted or is insufficient to make a recommendation regarding the electric utility's true-up filing, it shall notify the electric utility within ten (10) days of the electric utility's filing and identify the information required. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was responsive to the requirements, within ten (10) days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel, the processing timeline for the adjustment to the ECRM rates shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. For good cause shown, the commission may further suspend this timeline.

2. If the party requesting the information can demonstrate to the commission that the adjustment shall result in a reduction in the ECRM rates, the processing timeline shall continue with the best information available. When the electric utility provides the necessary information, the ECRM shall be adjusted again, if necessary, to reflect the additional information provided by the electric utility.

(6) Duration of ECRMs and Requirement for General Rate Case. Once an ECRM is approved by the commission, it shall remain in effect for a term of not more than four (4) years unless the commission earlier authorizes the modification, extension, or discontinuance of the ECRM in a general rate proceeding, although an electric utility may submit proposed rate schedules to implement periodic adjustments to its ECRM rates between general rate proceedings.

(A) If the commission approves an ECRM for an electric utility, the electric utility must file a general rate case with the effective date of new rates to be no later than four (4) years after the effective date of the commission order implementing the ECRM, assuming the maximum statutory suspension of the rates so filed.

(B) The four (4)-year period shall not include any periods in which the electric utility is prohibited from collecting any charges under the adjustment mechanism, or any period for which charges collected under the ECRM must be fully refunded. In the event a court determines that the ECRM is unlawful and all moneys collected are fully refunded as a result of such a decision, the electric utility shall be relieved of any obligation to file a rate case. The term fully refunded as used in this section does not include amounts refunded as a result of reductions in net environmental compliance costs or prudence adjustments.

(7) Prudence Reviews Respecting an ECRM. A prudence review of the costs subject to the ECRM shall be conducted no less frequently than at eighteen (18)-month intervals.

(A) All amounts ordered refunded by the commission shall include interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis in the same manner as described in subsection (5)(A).

(B) The staff shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred eighty (180) days after the staff initiates its prudence audit. The timing and frequency of prudence audits for each ECRM shall be established in the general rate proceeding in which the ECRM is established. The staff shall file notice within ten (10) days of starting its prudence audit. The commission shall issue an order not later than two hundred ten (210) days after the staff commences its prudence audit if no party to the proceeding in which the prudence audit is occurring files, within one hundred ninety (190) days of the staff's commencement of its prudence audit, a request for a hearing.

1. If the staff, OPC, or other party auditing the ECRM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's ECRM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel the processing timeline shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. For good cause shown, the commission may further suspend this timeline.

2. If the timeline is extended due to an electric utility's failure to timely provide sufficient responses to discovery, and a refund is due to the customers, the electric utility shall refund all imprudently incurred costs plus interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis in the same manner as described in subsection (5)(A).

(8) Disclosure on Customers' Bills. Any amounts charged under an ECRM approved by the commission shall be separately disclosed on each customer's bill. Proposed language regarding this disclosure shall be submitted to the commission for the commission's approval.

(9) Submission of Surveillance Monitoring Reports. Each electric utility with an approved ECRM shall submit to staff, OPC, and parties approved by the commission a Surveillance Monitoring Report in the form and having the content provided for by 4 CSR 240-3.162(6).

(A) The Surveillance Monitoring Report shall be submitted within fifteen (15) days of the electric utility's next scheduled United States Securities and Exchange Commission (SEC) 10-Q or 10-K filing with the initial submission within fifteen (15) days of the electric utility's next scheduled SEC 10-Q or 10-K filing following the effective date of the commission order establishing the ECRM.

(B) If the electric utility also has an approved fuel rate adjustment mechanism, the electric utility must submit a single Surveillance Monitoring Report for both the ECRM and the fuel rate adjustment mechanism. However, for the Surveillance Monitoring Report to be complete for the ECRM, it must include a list of all settlements in regards to environmental compliance causing the electric utility to incur expenses or make investments in excess of one hundred thousand dollars ($100,000) or fines against the electric utility in regards to environmental compliance greater than one hundred thousand dollars ($100,000) as required in 4 CSR 240-3.162(6)(A)5.G.

(C) Upon a finding that a utility has knowingly or recklessly provided materially false or inaccurate information to the commission regarding the surveillance data prescribed in 4 CSR 240-3.162(6), after notice and an opportunity for a hearing, the commission may suspend an ECRM or order other appropriate remedies as provided by law.

(10) Pre-Existing Adjustment Mechanisms, Tariffs, and Regulatory Plans. The provisions of this rule shall not affect the following:

(A) Any adjustment mechanism, rate schedule, tariff, incentive plan, or other ratemaking mechanism that was approved by the commission and in effect prior to the effective date of this rule; and

(B) Any experimental regulatory plan that was approved by the commission and in effect prior to the effective date of this rule.

(11) Nothing in this rule shall preclude a complaint case from being filed, as provided by law, on the grounds that a utility is earning more than a fair return on equity, nor shall an electric utility be permitted to use the existence of its ECRM as a defense to a complaint case based upon an allegation that it is earning more than a fair return on equity. If a complaint is filed on the grounds that a utility is earning more than a fair return on equity, the commission shall issue a procedural schedule that includes a clear delineation of the case timeline no later than sixty (60) days from the date the complaint is filed.

(12) Rule Review. The commission shall review the effectiveness of this rule by no later than December 31, 2011, and may, if it deems necessary, initiate rulemaking proceedings to revise this rule.

(13) Waiver of Provisions of this Rule. Provisions of this rule may be waived by the commission for good cause shown after an opportunity for a hearing.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000 and section 386.266, RSMo Supp. 2008. This rule originally filed as 4 CSR 240-20.091. Original rule filed Oct. 31, 2007, effective June 30, 2008, terminated Jan. 4, 2009. Refiled: Dec. 31, 2008, effective Aug. 30, 2009. Moved to 20 CSR 4240-20.091, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.266, RSMo 2005; and 393.140, RSMo 1939, amended 1949, 1967.*

***Rule Action Notice**: On December 4, 2008, the circuit court granted the moving parties' (Office of Public Counsel and Missouri Industrial Energy Consumers) motion for reversal and entered a judgment reversing the Public Service Commission's Final Order of Rulemaking. The circuit court's judgment reversing the commission's Final Order of Rulemaking became final on January 4, 2009. After January 4, 2009, 4 CSR 240-20.091 shall be terminated and of no further force and effect.*

20 CSR 4240-20.092 Definitions for Demand-Side Programs and Demand-Side Programs Investment Mechanisms

PURPOSE: This rule incorporates definitions for all terms used in 4 CSR 240-20.093 Demand-Side Programs Investment Mechanisms (DSIM) and 4 CSR 240-20.094 Demand-Side Programs.

(1) As used in 4 CSR 240-20.093 and 4 CSR 240-20.094, the following terms mean:

(A) Annual report means a report of information concerning a utility's demand-side programs having the content described in 4 CSR 240-20.093(9);

(B) Approved demand-side program means a demand-side program or program pilot which is approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs;

(C) Avoided costs or avoided utility costs means the cost savings obtained by substituting demand-side programs for existing and new supply-side resources. Avoided costs include avoided utility costs resulting from demand-side programs' energy savings and demand savings associated with generation, transmission, and distribution facilities including avoided probable environmental compliance costs. The utility shall use the integrated resource plan and risk analysis used in its most recently adopted preferred resource plan to calculate its avoided costs;

(D) Baseline demand forecast means a reference forecast of summer or winter peak demand at the customer class level and on the customer side of the meter, excluding the effects of any new demand-side programs but including the effects of naturally-occurring energy efficiency and any codes and standards that were in place and known to be enacted at the time the forecast is completed;

(E) Baseline energy forecast means a reference forecast of energy at the customer class level and on the customer side of the meter, excluding the effects of any new demand-side programs but including the effects of naturally-occurring energy efficiency and any codes and standards that were in place and known to be enacted at the time the forecast is completed;

(F) Cost recovery amount means the amount approved by the commission in a utility's filing for demand-side program approval or a DSIM rate adjustment case to provide the utility with cost recovery of demand-side program costs based on the approved cost recovery component of a DSIM;

(G) Cost recovery component of a DSIM means the methodology approved by the commission in a utility's filing for demand-side program approval to allow the utility to receive recovery of costs of approved demand-side programs with interest;

(H) Customer class means major customer rate groupings such as residential, small general service, large general service, and large power service;

(I) Deemed savings means the estimated measure-level annual energy savings and/or demand savings documented or calculated in the approved technical resource manual, technical reference manual (TRM), or statewide TRM, multiplied by the documented measure count. The demand-side program deemed savings is the sum of the deemed savings for all measures installed in a demand-side program. The demand-side portfolio deemed savings is the sum of all demand-side program deemed savings;

(J) Demand means the rate of electric power use over an hour measured in kilowatts (kW);

(K) Demand response means measures that decrease peak demand or shift demand to off-peak periods;

(L) Demand-side portfolio means all of a utility's demand-side programs at a defined point in time;

(M) Demand-side program means any program conducted by the utility to modify the net consumption of electricity on the retail customer's side of the electric meter, including, but not limited to, energy efficiency measures, load management, demand response, and interruptible or curtailable load, but not including deprivation of service or low-income weatherization;

(N) Demand-side programs investment mechanism, or DSIM, means a mechanism approved by the commission in a utility's filing for demand-side program approval to encourage investments in demand-side programs. The DSIM may include: a program cost recovery component of a DSIM, a throughput disincentive component of a DSIM, and an earnings opportunity component of a DSIM;

(O) Demand savings target means the demand savings level approved by the commission under 4 CSR 240-20.094(4)(I) or 4 CSR 240-20.094(5)(A)5. Demand savings targets are the baseline for determining the utility's demand-side portfolio's demand savings performance levels for the earnings opportunity component of a DSIM;

(P) DSIM amount means the sum of the program cost recovery amount, throughput disincentive amount, and earnings opportunity amount;

(Q) DSIM rate means the rate used to determine the charge on customers' bills for the portion of the DSIM amount assigned by the commission to a rate class;

(R) Earnings opportunity amount means the amount approved by the commission in a utility's filing for demand-side program approval or a rate adjustment case to provide the utility with an earnings opportunity amount based on the approved earnings opportunity component of a DSIM;

(S) Earnings opportunity component of a DSIM means the methodology approved by the commission in a utility's filing for demand-side program approval to allow the utility to receive an earnings opportunity. Any earnings opportunity component of a DSIM shall be implemented on a retrospective basis, and all energy and demand savings used to determine a DSIM earnings opportunity amount shall be verified and documented through EM&V reports;

(T) Economic potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from customer adoption of all cost-effective measures, regardless of customer preferences;

(U) Electric utility or utility means any electric corporation as defined in section 386.020, RSMo;

(V) Energy means the total amount of electric power that is used over a specified interval of time measured in kilowatt-hours (kWh);

(W) Energy efficiency means measures that reduce the amount of electricity required to achieve a given end-use;

(X) Energy savings target means the energy savings level approved by the commission under 4 CSR 240-20.094(4)(I) or 4 CSR 240-20.094(5)(A)6. Energy savings targets are the baseline for determining the utility's demand-side portfolio's energy savings performance levels for the earnings opportunity component of a DSIM;

(Y) Evaluation, measurement, and verification, or EM&V, means the performance of studies and activities intended to evaluate the process of the utility's program delivery and oversight and to estimate and/or verify the estimated annual energy and demand savings, and to report on the benefits, cost effectiveness, and other effects from demand-side programs, based on those estimated and/or verified energy and demand savings;

(Z) Filing for demand-side programs approval means a utility's filing for establishment, modification, or discontinuance of demand-side program(s) which may also include a simultaneous request for the establishment, modification, or discontinuance of a DSIM;

(AA) General rate proceeding means a general rate increase proceeding or complaint proceeding before the commission in which all relevant factors that may affect the costs or rates and charges of the electric utility are considered by the commission;

(BB) Interruptible or curtailable rate means a tariffed rate under which a customer receives a reduced charge in exchange for agreeing to allow the utility to withdraw the supply of electricity under certain specified conditions;

(CC) Market potential study means a quantitative analysis of the amount of energy and demand savings that may exist, is cost-effective, and could be realized through the implementation of demand-side programs, policies, and rate design;

(DD) Market transformation means the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective demand-side savings as a matter of standard practice;

(EE) Maximum achievable potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and ideal implementation conditions. Maximum achievable potential establishes a maximum target for demand-side savings that a utility can expect to achieve through its demand-side programs and involves incentives that represent a very high portion of total programs costs and very short customer payback periods. Maximum achievable potential is considered the hypothetical upper-boundary of achievable demand-side savings potential, because it presumes conditions that are ideal and not typically observed;

(FF) Measure means any device, technology, behavioral response mechanism, or operating procedure that makes it possible to deliver the same or better levels of energy service while—

1. Using less electricity than would otherwise be required to achieve a given end-use; or

2. Altering the time pattern of end-use electricity so as to decrease peak demand or shift demand to off-peak periods;

(GG) MEEIA means the Missouri Energy Efficiency Investment Act, section 393.1075, RSMo;

(HH) Net benefits means the program benefits measured and documented through EM&V reports, TRMs and statewide TRM, less the sum of the program costs including the design, administration, delivery, end-use measures, incentive payments to customers, EM&V, utility market potential studies, and statewide TRM or TRM and statewide TRM;

(II) Non-Energy Benefits means—

1. Direct benefits to participants in utility demand side programs, including, but not limited to, increased property values, increased productivity, decreased water and sewer bills, reduced operations and maintenance costs, improved tenant satisfaction, and increases to the comfort, health, and safety of participants and their families;

2. Direct benefits to utilities, including, but not limited to, reduced arrearage carrying costs, reduced customer collection calls/notices, reduced termination/reconnection costs, and reduced bad debt write-offs; or

3. Indirect benefits to society at large, including, but not limited to, job creation, economic development, energy security, public safety, reduced emissions and emission related health care costs, and other environmental benefits;

4. Non-Energy Benefits may be included in the total resource cost test (TRC) only if they result in avoided utility costs that may be calculated with a reasonable degree of confidence. Non-energy benefits may always be considered in the societal cost test.;

(JJ) Participant costs test (PCT) means a test of the cost-effectiveness of demand-side programs that measures the economics of a demand-side program from the perspective of the customers participating in the program;

(KK) Preferred resource plan means the utility's resource plan that is contained in the resource acquisition strategy most recently adopted by the utility's decision-makers in accordance with 4 CSR 240-22;

(LL) Probable environmental compliance costs means the costs to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility's decision-makers, may be reasonably expected to be incurred by the utility and are included in the integrated resource plan and risk analysis used in its most recently-adopted preferred resource plan;

(MM Program pilot means a demand-side program designed to operate on a limited basis for evaluation purposes before full implementation;

(NN) Ratepayer impact measure (RIM) test is a measure of the difference between the change in total revenues paid to a utility and the change in total cost incurred by the utility as a result of the implementation of demand-side programs. The benefits are the avoided costs as a result of implementation. The costs consist of incentives paid to participants, other costs incurred by the utility, and the loss in revenue as a result of diminished consumption, and the utility's earnings opportunity as a result of implementation of demand-side programs. Utility costs include the costs to administer, deliver, and evaluate each demand-side program and the costs of statewide TRM or TRM and statewide TRM;

(OO) Realistic achievable potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and realistic implementation conditions. Realistic achievable potential establishes a realistic target for demand-side savings that a utility can expect to achieve through its demand-side programs and involves incentives that represent a moderate portion of total program costs and longer customer payback periods when compared to those associated with maximum achievable potential;

(PP) Societal cost test means the total resource cost test with the addition of non-energy benefits;

(QQ) Staff means all personnel employed by the commission, whether on a permanent or contract basis, except: commissioners; commissioner support staff, including technical advisory staff; personnel in the secretary's office; and personnel in the general counsel's office, including personnel in the adjudication department. Employees in the staff counsel's office are members of the commission's staff;

(RR) Technical potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from a theoretical construct that assumes all feasible measures are adopted by customers of the utility regardless of cost or customer preference;

(SS) Technical resource manual, technical reference manual or TRM means a document used to quantify energy savings and demand savings attributable to energy efficiency and demand response programs within an electric utility's service territory. The TRM may be a statewide or utility-specific document that is approved by the commission;

(TT) Throughput disincentive means the electric utility's lost margin revenues that result from decreased retail sales volumes due to its demand-side programs;

(UU) Throughput disincentive amount means the amount approved by the commission in a utility's filing for demand-side program approval or a DSIM rate adjustment case to provide the utility with recovery of throughput disincentive based on the approved throughput disincentive component of a DSIM;

(VV) Throughput disincentive component of a DSIM means the methodology approved by the commission in a utility's filing for a demand-side program approval to allow the utility to receive recovery of throughput disincentive with interest;

(WW) Total resource cost test or TRC means a test that compares the sum of avoided utility costs, including avoided probable environmental costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demandside program and costs of statewide TRM or TRM and statewide TRM; and

(XX) Utility cost test (UCT) means a test that compares the sum of avoided utility costs, including avoided probable environmental costs, to the sum of all incremental costs of end use measures that are implemented due to the program, excluding participant contributions, plus utility costs to administer, deliver, and evaluate each demand-side program and costs of statewide TRM or TRM and statewide TRM.

(2) Upon request and for good cause shown, the commission may grant a variance from any provision of this rule.

AUTHORITY: section 393.1075.11, RSMo 2016. This rule originally filed as 4 CSR 240-20.092. Original rule filed Dec. 27, 2016, effective Oct. 30, 2017. Moved to 20 CSR 4240-20.092, effective Aug. 28, 2019.*

**Original authority: 393.1075, RSMo 2009.*

20 CSR 4240-20.093 Demand-Side Programs Investment Mechanisms

PURPOSE: This rule allows the establishment and operation of Demand-Side Programs Investment Mechanisms (DSIM), which allow periodic rate adjustments related to recovery of costs and utility incentives for investments in demand-side programs.

(1) The definitions of terms used in this section can be found in 4 CSR 240-20.092 Definitions for Demand-Side Programs and Demand-Side Programs Investment Mechanisms.

(2) Applications to establish, continue, or modify a Demand-Side Programs Investment Mechanism (DSIM). Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility shall file an application with the commission to establish, continue, or modify a DSIM in a utility's filing for demand-side program approval.

(A) An application to establish a DSIM shall include the following supporting information as part of, or in addition to, its direct testimony. Supporting workpapers shall be submitted with all models and spreadsheets provided as executable versions in native format with all links and formulas intact.

1. The notice provided to customers describing how the proposed DSIM will work, how any proposed DSIM rate will be determined, and how any DSIM rate will appear on customers' bills;

2. An example customer bill showing how the proposed DSIM shall be separately identified on affected customers' bills;

3. A complete, reasonably detailed, description and explanation of the design, rationale, and intended operation of the proposed DSIM;

4. Estimates of the effect of the DSIM and all other impacts of the demand-side program spending, in aggregate, on customer rates and average bills for each of the next five (5) years, and as a net present value of net benefits over the lifetime of the demand-side program impacts, for each rate class;

5. Estimates of the effect of the DSIM on earnings and key credit metrics for each of the next three (3) years including the level of earnings and key credit metrics expected to occur for each of the next three (3) years with and without the DSIM;

6. A complete, reasonably detailed, explanation of all the costs that shall be considered for recovery under the proposed DSIM and the specific account used for each cost item on the electric utility's books and records;

7. A complete, reasonably detailed, explanation of any change in business risk to the electric utility resulting from implementation of a DSIM in setting the electric utility's allowed return on equity, in addition to any other changes in business risk experienced by the electric utility;

8. A proposal for how the commission can determine if the DSIM is aligned with helping customers use energy more efficiently;

9. If the utility proposes to adjust its DSIM rates between general rate proceedings, proposed DSIM rate adjustment clause tariff sheets; and

10. If the utility proposes to adjust the DSIM amount between general rate proceedings, a complete, reasonably detailed, explanation of how the DSIM rates shall be established and how they will be adjusted for any over- and/or under-recovery amounts, as well as the impact on the DSIM amount as a result of, established, modified, or discontinued demand-side programs.

(B) If an electric utility files to modify its approved DSIM, the electric utility shall file with the commission and serve upon parties, as provided in section (15) below, the following supporting information as part of, or in addition to, direct testimony. Supporting workpapers shall be submitted with all models and spreadsheets provided as executable versions in native format with all links and formulas intact;

1. Information as required by subsection (2)(A), above;

2. Explanation of any proposed modification to the DSIM and why the proposed modification is being requested;

3. A complete, reasonably detailed, explanation of any change in business risk to the electric utility resulting from modification of a DSIM in setting the electric utility's allowed return on equity, in addition to any other changes in business risk experienced by the electric utility; and

4. Any additional information the commission orders to be provided.

(C) Any party to the application for a utility's filing for demand-side program approval may support or oppose the establishment, continuation, or modification of a DSIM and/or may propose an alternative DSIM for the commission's consideration including, but not limited to, modifications to any electric utility's proposed DSIM.

(D) The commission shall approve the establishment, continuation, or modification of a DSIM and associated tariff sheets if it finds the electric utility's approved demand-side programs are expected to result in energy and demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers and will assist the commission's efforts to implement state policy contained in section 393.1075, RSMo, to—

1. Provide the electric utility with timely recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs;

2. Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and

3. Provide timely earnings opportunities associated with cost-effective measurable and/or verifiable energy and demand savings;

(E) In addition to any other changes in business risk experienced by the electric utility, the commission shall consider changes in the utility's business risk resulting from establishment, continuation, or modification of the DSIM in setting the electric utility's allowed return on equity in general rate proceedings.

(F) In determining to approve a request to establish, modify, or continue a DSIM, the commission may consider, but is not limited to only considering, the expected magnitude of the impact of the utility's approved demand-side programs on the utility's costs, revenues, and earnings, the ability of the utility to manage all aspects of the approved demand-side programs, the ability to measure and verify the approved demand-side programs' impacts, any interaction among the various components of the DSIM that the utility may propose, and the incentives or disincentives provided to the utility as a result of the inclusion or exclusion of DSIM components as defined in 4 CSR 240-20.092(N). In this context the word "disincentives" means any barrier to the implementation of a DSIM. There is no penalty authorized in this section.

(G) Any cost recovery component of a DSIM shall be based on costs of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs. Indirect costs associated with demand-side programs, including but not limited to, costs of evaluation, measurement, and verification (EM&V), and/or utility's portion of statewide technical reference manual, shall be allocated to demand-side programs and thus shall be eligible for recovery through an approved DSIM. The commission shall approve any cost recovery component of a DSIM simultaneously with the programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

(H) Any throughput disincentive component of DSIM shall be based on energy or energy and demand savings from utility demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and will be determined as a result of energy and demand savings determined through EM&V.

1. The commission shall order any throughput disincentive component of a DSIM simultaneously with the demand-side programs approved in accordance with 4 CSR 240-20.094 Demand-Side Programs.

2. In a utility's filing in which a throughput disincentive component of a DSIM is considered, there is no requirement for any implicit or explicit utility throughput disincentive component of a DSIM or for a particular form of a throughput disincentive component of a DSIM.

3. Any explicit throughput disincentive component of a DSIM shall be implemented on a prospective basis.

(I) Any earnings opportunity component of a DSIM shall be based on the performance of demand-side programs approved by the commission in accordance with 4 CSR 240-20.094 Demand-Side Programs and shall include a methodology for determining the utility's earnings opportunity amount for individual demand-side programs based upon program performance relative to commission-approved performance metrics for each demand-side program.

1. Energy and demand savings targets approved by the commission for use in the earnings opportunity component of a DSIM are not necessarily the same as the incremental energy and demand savings goals and cumulative energy and demand savings goals specified in 4 CSR 240-20.094(2).

2. The commission shall order any earnings opportunity component of a DSIM simultaneously with the approval of the demand-side programs in accordance with 4 CSR 240-20.094 Demand-Side Programs.

3. Any earnings opportunity component of a DSIM shall be implemented on a retrospective basis and all energy and demand savings used to determine a DSIM earnings opportunity amount must be measured and verified through EM&V.

(J) If the DSIM proposed by the utility includes adjustments to DSIM rates between general rate proceedings, the DSIM shall include a provision to adjust the DSIM rates not less than annually to include a true-up for over- and under-recovery of the DSIM amount as well as the impact on the DSIM amount as a result of approved new, modified, or discontinued demand-side programs.

(K) If the commission approves an earnings opportunity component of a DSIM, such earnings opportunity component shall be binding on the commission for the entire term of the DSIM, and such DSIM shall be binding on the electric utility for the entire term of the DSIM, unless otherwise ordered or conditioned by the commission when approved.

(L) The commission shall apportion the DSIM amount to each customer class.

(3) Application for Discontinuation of a DSIM. The commission shall allow or require a DSIM to be discontinued or any component of a DSIM to be discontinued only after providing the opportunity for a hearing.

(A) When submitting an application to discontinue a DSIM, the electric utility shall file with the commission and serve on parties as provided in section (15), the following supporting information as part of, or in addition to, direct testimony. Supporting workpapers shall be submitted with all models and spreadsheets provided as executable versions in native format with all links and formulas intact:

1. An example of the notice to be provided to customers;

2. If the utility's DSIM allows adjustments of the DSIM rates between general rate proceedings, a complete, reasonably detailed, explanation of how the over-/under-recovery of the DSIM amount that the electric utility is proposing to discontinue shall be handled;

3. A complete, reasonably detailed, explanation of why the DSIM is no longer necessary to provide the electric utility a sufficient opportunity to recover demand-side programs costs, throughput disincentive, and/or to receive an earnings opportunity;

4. A complete, reasonably detailed, explanation of any change in business risk to the electric utility resulting from discontinuation of the DSIM in setting the electric utility's allowed return on equity, in addition to any other changes in business risk experienced by the electric utility; and

5. Any additional information the commission orders to be provided.

(B) Any party to the utility's filing for demand-side program approval may oppose the discontinuation of a DSIM or any component of a DSIM.

(C) In addition to any other changes in business risk experienced by the electric utility, the commission may take into account any change in business risk to the electric utility resulting from discontinuance of the DSIM in setting the electric utility's allowed return on equity in a general rate proceeding.

(D) If the utility requests that cost recovery be discontinued, in its notice to customers, the electric utility shall include a commission-approved description of why it believes the cost recovery component of the DSIM should be discontinued.

(4) Requirements for Adjustments of DSIM Rates Between General Rate Proceedings. An electric utility with a DSIM shall file to adjust its DSIM rated no less often than annually.

(A) The electric utility shall file tariff sheets to adjust its DSIM rates accompanied by supporting testimony and contain at least the following supporting information. All models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact.

1. Amount of revenue that it has over-/under-recovered through the most recent recovery period by rate class.

2. Proposed positive or negative adjustments by rate class.

3. Electric utility's short-term borrowing rate.

4. Proposed adjustments to the current DSIM rates.

5. Complete documentation for the proposed adjustments to the current DSIM rates.

6. Any additional information the commission ordered to be provided.

(B) The staff shall examine and analyze the information filed by the electric utility and additional information obtained through discovery, if any, to determine if the proposed adjustments to the DSIM amount and DSIM rates are in accordance with the provisions of this rule, section 393.1075, RSMo, and the DSIM established, modified, or continued in the most recent filing for demand-side program approval. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files its tariff sheets to adjust its DSIM rates. If the adjustments to the DSIM rates are in accordance with the provisions of this rule, section 393.1075, RSMo, and the DSIM established, modified, or continued in the most recent filing for demand-side program approval, the commission shall either issue an interim rate adjustment order approving the tariff sheets within sixty (60) days of the electric utility's filing or, if no such order is issued, the adjustments to the DSIM rates shall take effect sixty (60) days after the tariff sheets were filed. If the adjustments to the DSIM rates are not in accordance with the provisions of this rule, section 393.1075, RSMo, or the DSIM established, modified, or continued in the most recent filing for demand-side program approval, the commission shall reject the proposed tariff sheets within sixty (60) days of the electric utility's filing and may instead order the filing of interim tariff sheets that implement its decision.

(C) Adjustments to the DSIM rates shall reflect a comprehensive measurement of both increases and decreases to the DSIM amount established in the most recent demand-side program approval or DSIM rate adjustment case plus the increases and decreases to the DSIM amount which occurred since the most recent demand-side program approval or DSIM rate adjustment case. All DSIM rate adjustments shall include a true-up of past DSIM collections based on the latest EM&V results where applicable. Any over-/under-recovered amounts will be accounted for in the going forward DSIM rates.

(D) The electric utility shall be current on its submission of its Surveillance Monitoring Reports as required in section (10) and its annual reports as required in section (9) in order to increase the DSIM rates.

(E) If the staff, public counsel, or other party believes the electric utility has not met the filing requirements of subsection (4)(A), it shall notify the electric utility within ten (10) days of the electric utility's filing of an application or tariff sheets to adjust DSIM rates and identify the information required. The electric utility shall submit the information identified by the party, or shall notify the party that it believes the information submitted was in compliance with the requirements of subsection (4)(A), within ten (10) days of the request. A party who notifies the electric utility it believes the electric utility has not submitted all the information required by subsection (4)(A) and as ordered by the commission in a previous proceeding and receives notice from the electric utility that the electric utility believes it has submitted all required information may file a motion with the commission for an order directing the electric utility to produce that information, i.e., a motion to compel. While the commission is considering the motion to compel, the processing timeline for the adjustment to increase DSIM rates shall be suspended. If the commission then issues an order requiring the information be submitted, the time necessary for the information to be submitted shall further extend the processing timeline for the adjustment to increase DSIM rates. For good cause shown, the commission may further suspend this timeline. Any delay in submitting sufficient information in compliance with subsection (4)(A) or a commission order in a previous proceeding in a request to decrease DSIM rates shall not alter the processing timeline.

(5) Implementation of DSIM. Once a DSIM is established, modified, or discontinued, in lieu of contemporaneous rate recovery the utility may request use of deferral accounting for MEEIA financial impacts using the utility's latest approved weighted average cost of capital until the cut-off date for cost recognition ordered in the utility's next general rate proceeding.

(6) Duration of DSIM. Once a DSIM is approved by the commission, it shall remain in effect for the term established by the commission in the order approving that DSIM so as to allow full recovery of all DSIM amounts. During the term of an approved DSIM the utility or any party to the application for the utility's filing for approval of a demand-side program may propose modifications to the DSIM. No modification of a utility's DSIM shall be made without the assent of the utility.

(7) Disclosure. Regardless of whether or not the utility requests adjustments of its DSIM rates between general rate proceedings, any amounts charged under a DSIM approved by the commission, including any earnings opportunity allowed by the commission, shall be separately disclosed on each customer's bill. Proposed language regarding this disclosure shall be submitted to and approved by the commission before it appears on customers' bills. The disclosure shall also appear on the utility's websites.

(8) Evaluation, Measurement, and Verification (EM&V) of the Process and Impact of Demand-Side Programs. Each electric utility shall hire an independent contractor to perform and report EM&V of each commission-approved demand-side program in accordance with 4 CSR 240-20.094 Demand-Side Programs. The utility shall provide oversight and guidance to the independent EM&V contractor, but shall not influence the independent EM&V contractor's report(s). The commission shall hire an independent contractor to audit and report on the work of each utility's independent EM&V contractor. The commission staff shall provide oversight and guidance to the independent commission contractor, but shall not influence the independent contractor's audit(s). Staff counsel shall provide legal representation to the independent contractor in the event the independent contractor is required to testify before the commission.

(A) Each utility's EM&V budget shall not exceed five percent (5%) of the utility's total budget for all approved demand-side program costs.

(B) The cost of the commission's EM&V contractor shall—

1. Not be a part of the utility's budget for demand-side programs; and

2. Be included in the Missouri Public Service Commission Assessment for each utility.

(C) EM&V draft reports from the utility's contractor for each approved demand-side program shall be delivered simultaneously to the utility and to parties of the case in which the demand-side program was approved.

(D) EM&V final reports from the utility's contractor of each approved demand-side program shall—

1. Document, include analysis, and present any applicable recommendations for at least the following. All models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact:

A. Process evaluation and recommendations, if any; and

B. Impact evaluation—

(I) The annual gross and net demand savings and energy savings achieved under each demand-side program and the techniques used to estimate annual demand savings and energy savings;

(II) For demand-side programs subject to cost-effectiveness tests, include total resource cost test, societal cost test, utility cost test, participant cost test, and nonparticipant cost test of each demand-side program; and

(III) Determine the net benefits achieved for each demand-side program subject to cost-effectiveness tests and for the portfolio of such programs using the utility cost test (UCT) methodology;

2. Be completed by the EM&V contractor on a schedule approved by the commission at the time of demand-side program approval in accordance with 4 CSR 240-20.094(4); and

3. Be filed with the commission in the case in which the utility's demand-side program approval was received and delivered simultaneously to the utility and the parties of the case in which the demand-side program was approved.

(E) Electric utility's EM&V contractors shall—

1. Include specific methodology for performing EM&V work; and

2. Utilize the TRM approved with the utility's application for its DSIM and demand-side portfolio.

(9) Demand-Side Program Annual Report. Each electric utility with one (1) or more approved demand-side programs shall file an annual report by no later than ninety (90) days after the end of each program year, make a public version available for publication on the commission's website, and serve a copy on each party to the case in which the demand-side programs were last established, modified, or continued. Interested parties may file comments with the commission concerning the content of the utility's annual report within thirty (30) days of its filing. Annual reports shall include at a minimum the following information, and all models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact:

(A) An affidavit attesting to the veracity of the information; and

(B) A list of all approved demand-side programs and the following information for each approved demand-side program:

1. Actual amounts expended by year, including customer incentive payments;

2. Peak demand and energy savings impacts and the techniques used to estimate those impacts;

3. A comparison of the estimated actual annual peak demand and energy savings impacts to the annual demand and energy savings targets approved by the commission under 4 CSR 240-20.094(4)(I) or 4 CSR 240-20.094(5)(A)5.;

4. For market transformation demand-side programs, a quantitative and qualitative assessment of the progress being made in transforming the market;

5. A comparison of actual and budgeted demand-side program costs, including an explanation of any increase or decrease of more than twenty percent (20%) in the cost of a demand-side program;

6. The avoided costs and the techniques used to estimate those costs;

7. The estimated cost-effectiveness of the demand-side program and a comparison to the estimates made by the utility at the time the demand-side program was approved;

8. The estimated net benefits of each demand-side program and the demand-side portfolio;

9. For each demand-side program where one (1) or more customers have opted out of demand-side programs pursuant to section 393.1075.7, RSMo, a listing of the customer(s) who have opted out of participating in demand-side programs;

10. As part of its annual report, the electric utility shall file or provide a reference to the commission case that contains a copy of the EM&V report for the most recent annual reporting period; and

11. Demonstration of relationship of the demand-side programs to demand-side resources in latest filed 4 CSR 240-22 compliance filing.

(10) Submission of Surveillance Monitoring Reports. Each electric utility with an approved DSIM shall submit to staff, public counsel, and parties approved by the commission a Surveillance Monitoring Report. Each electric utility with a DSIM shall submit, as page 6 of the Surveillance Monitoring Report, a quarterly progress report in a format agreed upon by the utility and staff, and all models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact. The report shall be submitted to the staff, public counsel, and stakeholders approved by the commission.

(A) The Surveillance Monitoring Report shall be submitted within fifteen (15) days of the electric utility's next scheduled United States Securities and Exchange Commission (SEC) 10-Q or 10-K filing with the initial submission within fifteen (15) days of the electric utility's next scheduled SEC 10-Q or 10-K filing following the effective date of the commission order establishing the DSIM.

(B) If the electric utility also has an approved environmental cost recovery mechanism or a fuel cost adjustment mechanism, the electric utility shall submit a single Surveillance Monitoring Report for all mechanisms.

(C) Upon a finding that a utility has knowingly or recklessly provided materially false or inaccurate information to the commission regarding the surveillance data prescribed in this section, after notice and an opportunity for a hearing, the commission may suspend a DSIM or order other appropriate remedies as provided by law.

(D) Disagreements about the report format or content shall be settled by the commission.

(11) Prudence Reviews. A prudence review of the costs subject to the DSIM shall be conducted no less frequently than at twenty-four-(24-) month intervals.

(A) All amounts ordered refunded by the commission shall include interest at the electric utility's short-term borrowing rate.

(B) The staff shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred fifty (150) days after the staff initiates its prudence audit. The timing and frequency of prudence audits for DSIM shall be established in the utility's filing for demand-side program approval in which the DSIM is established. The staff shall file notice within ten (10) days of starting its prudence audit. The commission shall issue an order not later than two hundred ten (210) days after the staff commences its prudence audit if no party to the proceeding in which the prudence audit is occurring files, within one hundred sixty (160) days of the staff's commencement of its prudence audit, a request for a hearing.

1. If the staff, public counsel, or other party auditing the DSIM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's DSIM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel, the processing timeline shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. For good cause shown, the commission may further suspend this timeline.

2. If the timeline is extended due to an electric utility's failure to timely provide sufficient responses to discovery and a refund is due to the customers, the electric utility shall refund all imprudently incurred costs plus

interest at the electric utility's short-term borrowing rate.

(12) Tariffs and Regulatory Plans. The provisions of this rule shall not affect—

(A) Any adjustment mechanism, rate schedule, tariff, incentive plan, or other ratemaking mechanism that was approved by the commission and in effect prior to the effective date of this rule; and

(B) Any experimental regulatory plan that was approved by the commission and in effect prior to the effective date of this rule.

(13) Nothing in this rule shall preclude a complaint case from being filed, as provided by law.

(14) Variances. Upon request and for good cause shown, the commission may grant a variance from any provision of this rule.

(15) Party status and providing to other parties affidavits, testimony, information, reports, and workpapers in related proceedings subsequent to the utility's filing for demand-side program approval, modification, or continuation of a DSIM.

(A) A person or entity granted intervention in a utility's filing for demand-side program approval in which a DSIM is approved by the commission shall have the right to be a party to any subsequent related periodic rate adjustment proceeding without the necessity of applying to the commission for intervention; however, such person or entity shall file a notice of intention to participate within the intervention period. Public Counsel and the commission's staff do not need to file a notice of intention to participate. In any subsequent utility's filing for demand-side program approval, such person or entity must seek and be granted status as an intervenor to be a party to that proceeding.

(B) Affidavits, testimony, information, reports, and workpapers to be filed or submitted in connection with a subsequent related annual DSIM rate adjustment proceeding or utility's filing for demand-side program approval to modify, continue, or discontinue the same DSIM shall be served on or submitted to all parties from the prior related demand-side program approval proceeding and on all parties from any subsequent related periodic rate adjustment proceeding or utility's filing for demand-side program approval to modify, continue, or discontinue the same DSIM, concurrently with filing the same with the commission or submitting the same to the manager of the energy resource analysis section of the staff and public counsel.

(C) A person or entity not a party to the utility's filing for demand-side program approval in which a DSIM is approved by the commission may timely apply to the commission for intervention, pursuant to 4 CSR 240-2.075(2) through (4) of the commission's rule on intervention, respecting any related subsequent periodic rate adjustment proceeding or, pursuant to 4 CSR 240-2.075(1) through (5), respecting any subsequent utility's filing for demand-side program approval to modify, continue, or discontinue the same DSIM.

(16) Missouri Energy Efficiency Investment Act (MEEIA) Rate Design Modifications.

(A) An electric utility may request modification of its DSIM rates by filing tariff schedule(s) with the commission as part of—

1. An application for approval of demand-side programs or a demand-side program plan and a DSIM; or

2. A general rate case proceeding.

(B) Any request for modification of a rate design shall include with the filing supporting documentation for the request, including but not limited to, workpapers, data, computer model documentation, analysis, and other supporting information to support and explain the modification of the rate design. All information shall be labeled and all spreadsheets shall be provided as executable versions with all links and formulas intact.

(C) Right to Discovery Unaffected. In addressing certain discovery matters and the provision of certain information by electric utilities, this rule is not intended to restrict the discovery rights of any party.

AUTHORITY: section 393.1075.11, RSMo 2016. This rule originally filed as 4 CSR 240-20.093. Original rule filed Oct. 4, 2010, effective May 30, 2011. Amended: Filed Dec. 27, 2016, effective Oct. 30, 2017. Moved to 20 CSR 4240-20.093, effective Aug. 28, 2019.*

**Original authority: 393.1075, RSMo 2009.*

20 CSR 4240-20.094 Demand-Side Programs

PURPOSE: This rule sets forth the definitions, requirements, and procedures for filing and processing applications for approval, modification, and discontinuance of electric utility demand-side programs. This rule also sets forth requirements and procedures related to customer opt-out, tax credits, monitoring customer incentives, and collaborative guidelines for demand-side programs.

(1) The definitions of terms used in this section can be found in 4 CSR 240-20.092 Definitions for Demand-Side Programs and Demand-Side Programs Investment Mechanisms.

(2) Guideline to Review Progress Toward an Expectation that the Electric Utility's Demand-Side Programs Can Achieve a Goal of All Cost-Effective Demand-Side Savings. The goals established in this section are not mandatory and no penalty or adverse consequence will accrue to a utility that is unable to achieve the listed annual energy and demand savings goals.

(A) The commission shall use the greater of the annual realistic amount of achievable energy savings and demand savings as determined through a market potential study or the following incremental annual demand-side savings goals as a guideline to review and determine whether the utility's demand-side programs can achieve a goal of all cost-effective demand-side savings:

1. For the utility's approved first program year: three-tenths percent (0.3%) of total annual energy and one percent (1.0%) of annual peak demand;

2. For the utility's approved second program year: five-tenths percent (0.5%) of total annual energy and one percent (1.0%) of annual peak demand;

3. For the utility's approved third program year: seven-tenths percent (0.7%) of total annual energy and one percent (1.0%) of annual peak demand;

4. For the utility's approved fourth program year: nine-tenths percent (0.9%) of total annual energy and one percent (1.0%) of annual peak demand;

5. For the utility's approved fifth program year: one-and-one-tenth percent (1.1%) of total annual energy and one percent (1.0%) of annual peak demand;

6. For the utility's approved sixth program year: one-and-three-tenths percent (1.3%) of total annual energy and one percent (1.0%) of annual peak demand;

7. For the utility's approved seventh program year: one-and-five-tenths percent (1.5%) of total annual energy and one percent (1.0%) of annual peak demand;

8. For the utility's approved eighth program year: one-and-seven-tenths percent (1.7%) of total annual energy and one percent (1.0%) of annual peak demand; and

9. For the utility's approved ninth and subsequent program years, unless additional energy savings and demand savings goals are established by the commission: one-and-nine-tenths percent (1.9%) of total annual energy

and one percent (1.0%) of annual peak demand each year.

(B) The commission shall also use the greater of the cumulative annual realistic amount of achievable energy savings and demand savings as determined through a market potential study or the following cumulative demand-side savings goals as a guideline to review and determine whether the utility's demand-side programs can achieve a goal of all cost-effective demand-side savings:

1. For the utility's approved first program year: three-tenths percent (0.3%) of total annual energy and one percent (1.0%) of annual peak demand;

2. For the utility's approved second program year: eight-tenths percent (0.8%) of total annual energy and two percent (2.0%) of annual peak demand;

3. For the utility's approved third program year: one-and-five-tenths percent (1.5%) of total annual energy and three percent (3.0%) of annual peak demand;

4. For the utility's approved fourth program year: two-and-four-tenths percent (2.4%) of total annual energy and four percent (4.0%) of annual peak demand;

5. For the utility's approved fifth program year: three-and-five-tenths percent (3.5%) of total annual energy and five percent (5.0%) of annual peak demand;

6. For the utility's approved sixth program year: four-and-eight-tenths percent (4.8%) of total annual energy and six percent (6.0%) of annual peak demand;

7. For the utility's approved seventh program year: six-and-three-tenths percent (6.3%) of total annual energy and seven percent (7.0%) of annual peak demand;

8. For the utility's approved eighth program year: eight percent (8.0%) of total annual energy and eight percent (8.0%) of annual peak demand; and

9. For the utility's approved ninth year and subsequent program years, unless additional energy savings and demand savings goals are established by the commission: nine-and-nine-tenths percent (9.9%) of total annual energy and nine percent (9.0%) of annual peak demand for the approved ninth year, and then increasing by one-and-nine-tenths percent (1.9%) of total annual energy and by one percent (1.0%) of annual peak demand each year thereafter.

(3) Utility Market Potential Studies.

(A) The market potential study shall—

1. Consider both primary data and secondary data and analysis for the utility's service territory;

2. Be updated with primary data and analysis no less frequently than every three (3) years. To the extent that primary data for each utility service territory is unavailable or insufficient, the market potential study may also rely on or be supplemented by data from secondary sources and relevant data from other geographic regions;

3. Be prepared by an independent third party. The utility shall provide oversight and guidance to the independent market potential contractor, but shall not influence the independent market potential study contractor's reports; and

4. Include an estimate of the achievable potential, regardless of cost-effectiveness, of energy savings from low-income demand-side programs. Energy savings from multifamily buildings that house low-income households may count toward this target.

(B) The utility shall provide an opportunity for commission staff and stakeholder review and input in the planning stages of the potential study including review of assumptions and methodology in advance of the performance of the study.

(4) Applications for Approval of Electric Utility Demand-Side Programs or Portfolio. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility may file an application with the commission for approval of a demand-side portfolio.

(A) Prior to filing for demand-side programs approval, the electric utility shall hold a stakeholder advisory meeting to receive input on the major components of its filing.

(B) As part of its application for approval of demand-side programs, the electric utility shall file or provide a reference to the commission case that contains any of the following information. All models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact:

1. A current market potential study. If the market potential study of the electric utility that is filing for approval of demand-side programs or a demand-side portfolio encompasses more than just the utility's service territory, the sampling methodology shall reflect the utility's service territory and shall provide statistically significant results for that utility:

A. Complete documentation of all assumptions, definitions, methodologies, sampling techniques, and other aspects of the current market potential study;

B. Clear description of the process used to identify the broadest possible list of measures and groups of measures for consideration;

2. Clear description of the process and assumptions used to determine technical potential, economic potential, maximum achievable potential, and realistic achievable potential for a twenty- (20-) year planning horizon for major end-use groups (e.g., lighting, space heating, space cooling, refrigeration, motor drives, etc.) for each customer class; and

3. Identification and discussion of the twenty- (20-) year baseline energy and demand forecasts. If the baseline energy and demand forecasts in the current market potential study differ from the baseline forecasts in the utility's most recent 4 CSR 240-22 triennial compliance filing, the current market potential study shall provide a comparison of the two (2) sets of forecasts and a discussion of the reasons for any differences between the two (2) sets of forecasts. The twenty- (20-) year baseline energy and demand forecasts shall account for the following:

A. Discussion of the treatment of all of the utility's customers who have opted out;

B. Future changes in building codes and/or appliance efficiency standards;

C. Changes in naturally occurring customer combined heat and power applications;

D. Third party and other naturally occurring demand-side savings; and

E. The increasing efficiency of advanced technologies.

(C) Demonstration of cost-effectiveness for each demand-side program and for the total of all demand-side programs of the utility. At a minimum, the electric utility shall provide all workpapers, with all models and spreadsheets provided as executable versions in native format with all links and formulas intact, and include:

1. The total resource cost (TRC) test and a detailed description of the utility's avoided costs calculations and all assumptions used in the calculation;

2. The utility shall also include calculations for the utility cost test, the participant test, the RIM test, and the societal cost test;

3. The impacts on annual revenue requirements and net present value of annual revenue requirements as a result of the integration analysis in accordance with 4 CSR 240-22.060 over the twenty- (20-) year planning horizon; and

4. The impacts from all demand-side programs included in the application on any postponement of new supply-side resources and the early retirement of existing supply-side resources, including annual and net present value of any lost utility earnings related thereto.

(D) Detailed description of each proposed demand-side program, including all workpapers with all models and spreadsheets provided as executable versions in native format with all links and formulas intact, to include at least:

1. Customers targeted;
2. Measures and services included;
3. Customer incentives ranges;
4. Proposed promotional techniques;
5. Specification of whether the demand-side program will be administered by the utility or a contractor;
6. Projected gross and net annual and lifetime energy savings;
7. Proposed energy savings targets;
8. Projected gross and net annual demand savings;
9. Proposed demand savings targets;
10. Net-to-gross factors;
11. Size of the potential market and projected penetration rates;
12. Any market transformation elements included in the demand-side program and an evaluation, measurement, and verification (EM&V) plan for estimating, measuring, and verifying the energy and demand savings that the market transformation efforts are expected to achieve;
13. EM&V plan including at least the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-20.093(7);
14. Budget information in the following categories:
    A. Administrative costs listed separately for the utility and/or program administrator;
    B. Demand-side program incentive costs;
    C. Estimated equipment and installation costs, including any customer contributions;
    D. EM&V costs; and
    E. Miscellaneous itemized costs, some of which may be an allocation of total costs for overhead items such as the market potential study or the statewide technical reference manual;
15. Description of all strategies used to minimize free riders;
16. Description of all strategies used to maximize spillover; and
17. For demand-side program plans, the proposed implementation schedule of individual demand-side programs.

(E) Demonstration and explanation in quantitative and qualitative terms of how the utility's demand-side programs are expected to make progress towards a goal of achieving all cost-effective demand-side savings over the life of the demand-side programs. Should the expected demand-side savings fall short of the incremental annual demand-side savings goals and/or the cumulative demand-side savings goals in section (2), the utility shall provide detailed explanation of why the incremental annual demand-side savings goals and/or the cumulative demand-side savings goals cannot be expected to be achieved, and the utility shall bear the burden of proof.

(F) Identification of demand-side programs which are supported by the electric utility and at least one (1) other electric or gas utility (joint demand-side programs).

(G) Designation of Program Pilots. For demand-side programs designed to operate on a limited basis for evaluation purposes before full implementation (program pilot), the utility shall provide as much of the information required under subsections (2)(C) through (E) of this rule as is practical and shall include explicit questions that the program pilot will address, the means and methods by which the utility proposes to address the questions the program pilot is designed to address, a provisional cost-effectiveness evaluation if the program is subject to a cost-effectiveness test under section 393.1075.4, RSMo, the proposed geographic area, and duration for the program pilot.

(H) Any existing demand-side program with tariff sheets in effect prior to the effective date of this rule shall be included in the initial application for approval of demand-side programs if the utility intends for unrecovered and/or new costs related to the existing demand-side program be included in the DSIM. The commission shall approve, approve with modification acceptable to the electric utility, or reject such applications for approval of demand-side program plans within one hundred twenty (120) days of the filing of an application under this section only after providing the opportunity for a hearing. In the case of a utility filing an application for approval of an individual demand-side program, the commission shall approve, approve with modification acceptable to the electric utility, or reject applications within sixty (60) days of the filing of an application under this section only after providing the opportunity for a hearing.

(I) The commission shall consider the TRC test a preferred cost-effectiveness test. For demand-side programs and program plans that have a TRC test ratio greater than one (1), the commission shall approve demand-side programs or program plans, budgets, and demand and energy savings targets for each demand-side program it approves, provided it finds that the utility has met the filing and submission requirements of this rule and the demand-side programs—

1. Are consistent with a goal of achieving all cost-effective demand-side savings;
2. Have reliable evaluation, measurement, and verification plans; and
3. Are included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility.

(J) The commission shall approve demand-side programs targeted to low-income customers or general education campaigns, if the commission determines that the utility has met the filing and submission requirements of this rule, the demand-side programs are in the public interest, and the demand-side programs meet the requirements stated in subsection (4)(I). If a demand-side program is targeted to low-income customers, the electric utility must also state how the electric utility will assess the expected and actual effect of the demand-side program on the utility's bad debt expenses, customer arrearages, and disconnections.

(K) The commission shall approve demand-side programs which have a TRC test ratio less than one (1), if the commission finds the utility has met the filing and submission requirements of this rule and the costs of such demand-side programs above the level determined to be cost-effective are funded by the customers participating in the demand-side programs or through tax or other governmental credits or incentives specifically designed for that purpose and meet the requirements as stated in subsection (4)(I).

(L) Utilities shall file and receive approval of associated tariff sheets prior to implementation of approved demand-side programs.

(M) The commission shall simultaneously approve, approve with modification acceptable to the utility, or reject the utility's DSIM proposed pursuant to 4 CSR 240-20.093.

(5) Applications for Approval of Modifications to Electric Utility Demand-Side Programs.

(A) Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility—

1. Shall file an application with the commission for modification of demand-side programs when there is a variance of twenty percent (20%) or more in the budget approved by the commission under subsection (4)(I) or other commission order(s) and/or any demand-side program design modification which is no longer covered by the approved tariff sheets for the demand-side program;
2. The application shall include a complete, reasonably detailed, explanation for

and documentation of the proposed modifications to each of the filing requirements in section (3). All models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact;

3. The electric utility shall serve a copy of its application to all parties to the case under which the demand-side programs were approved;

4. The parties shall have thirty (30) days from the date of filing of an application to object to the application to modify;

5. If no objection is raised within thirty (30) days, the commission shall approve, approve with modification acceptable to the electric utility, or reject such applications for approval of modification of demand-side programs within forty-five (45) days of the filing of an application under this section, subject to the same guidelines as established in subsection (4)(I);

6. If objections to the application are raised, the commission shall provide the opportunity for a hearing.

(B) For any demand-side program design modifications approved by the commission, the utility shall file for and receive approval of associated tariff sheets prior to implementation of approved modifications.

(6) Applications for Approval to Discontinue Electric Utility Demand-Side Programs. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 393.1075, RSMo, an electric utility may file an application with the commission to discontinue demand-side programs.

(A) The application shall include the following information. All models and spreadsheets shall be provided as executable versions in native format with all links and formulas intact.

1. Complete, reasonably detailed explanation for the utility's decision to request to discontinue a demand-side program.

2. EM&V reports for the demand-side program in question, if available.

3. Date by which a final EM&V report for the demand-side program in question will be filed.

(B) If the TRC calculated for a demand-side program not targeted to low-income customers or a general education campaign is not cost-effective, the electric utility shall identify the causes why and present possible demand-side program modifications that could make the demand-side program cost-effective. If analysis of these modified demand-side program designs suggests that none would be cost-effective, the demand-side program may be discontinued. In this case, the utility shall describe how it intends to end the demand-side program and how it intends to achieve the energy and demand savings initially estimated for the discontinued demand-side program. Nothing herein requires utilities to end any demand-side program which is subject to a cost-effectiveness test deemed not cost-effective immediately. Utilities proposal for any discontinuation of a demand-side program should consider, but not be limited to: the potential impact on the market for energy efficiency services in its territory; the potential impact to vendors and the utilities relationship with vendors; the potential disruption to the market and to customer outreach efforts from immediate starting and stopping of demand-side programs; and whether the long term prospects indicate that continued pursuit of a demand-side program will result in a long-term cost-effective benefit to ratepayers.

(C) The commission shall approve or reject such applications for discontinuation of utility demand-side programs within thirty (30) days of the filing of an application under this section only after providing an opportunity for a hearing.

(7) Provisions for Customers to Opt-Out of Participation in Utility Demand-Side Programs.

(A) Any customer meeting one (1) or more of the following criteria shall be eligible to opt-out of participation in utility-offered demand-side programs:

1. The customer has one (1) or more accounts within the service territory of the electric utility that has a demand of five thousand (5,000) kW or more;

2. The customer operates an interstate pipeline pumping station, regardless of size; or

3. The customer has accounts within the service territory of the electric utility that have, in aggregate across its accounts, a coincident demand of two thousand five hundred (2,500) kW or more in the previous twelve (12) months, and the customer has a comprehensive demand-side or energy efficiency program and can demonstrate an achievement of savings at least equal to those expected from utility-provided demand-side programs. The customer shall submit to commission staff sufficient documentation to demonstrate compliance with these criteria, including, but not limited to:

A. Lists of all energy efficiency measures with work papers to show energy savings and demand savings. This can include engineering studies, cost benefit analysis, etc.;

B. Documentation of anticipated lifetime of installed energy efficiency measures;

C. Invoices and payment requisition papers;

(B) For utilities with automated meter reading and/or advanced metering infrastructure capability, the measure of demand is the customer coincident highest billing demand of the individual accounts during the twelve (12) months preceding the opt-out notification.

(C) Any confidential business information submitted as documentation shall be clearly designated as such in accordance with 4 CSR 240-2.135.

(D) Opt-out in accordance with paragraphs (7)(A)1., 2., and 3. shall be in effect for ten years, beginning with the calendar year subsequent to the submission of the opt-out.

(E) Written notification of opt-out from customers meeting the criteria under paragraph (7)(A)1. or 2. shall be sent to the utility serving the customer. Written notification of opt-out from customers meeting the criteria under paragraph (7)(A)3. shall be sent to the utility serving the customer and the manager of the energy resources department of the commission or submitted through the commission's electronic filing and information system (EFIS) as a non-case-related filing. In instances where only the utility is provided notification of opt-out from customers meeting the criteria under paragraph (7)(A)3., the utility shall forward a copy of the written notification to the manager of the energy resources department of the commission and submit the notice of opt-out through EFIS as a non-case-related filing.

(F) Written notification of opt-out from customer shall include at a minimum:

1. Customer's legal name;

2. Identification of location(s) and utility account number(s) of accounts for which the customer is requesting to opt-out from demand-side program's benefits and costs; and

3. Demonstration that the customer qualifies for opt-out.

(G) For customers filing notification of opt-out under paragraph (7)(A)1. or 2., notification of the utility's acknowledgement or plan to dispute a customer's notification to opt-out of participation in demand-side programs shall be delivered in writing to the customer and to the staff within thirty (30) days of when the utility received the written notification of opt-out from the customer.

(H) For customers filing notification of opt-out under paragraph (7)(A)3., the staff will make the determination of whether the customer meets the criteria of paragraph (7)(A)3. Notification of the staff's acknowledgement or disagreement with customer's qualification to opt-out of participation in demand-side programs shall be delivered to the customer and to the utility within thirty (30) days of when the staff received complete documentation of compliance with paragraph

(7)(A)3.

(I) Timing and Effect of Opt-Out Provisions.

1. A customer notice of opt-out shall be received by the utility no earlier than September 1 and not later than October 30 to be effective for the following calendar year.

2. For that calendar year in which the customer receives acknowledgement of opt-out and each successive calendar year until the customer revokes the notice pursuant to subsection (7)(K), or the customer is notified that it no longer satisfies the requirements of paragraphs (7)(A)1., 2., or 3., none of the costs of approved demand-side programs of an electric utility offered pursuant to 4 CSR 240-20.093, 4 CSR 240-20.094, or by other authority and no other charges implemented in accordance with section 393.1075, RSMo, shall be assigned to any account of the customer, including its affiliates and subsidiaries listed on the customer's written notification of opt-out.

(J) Dispute Notices. If the utility or staff provides notice that a customer does not meet the opt-out criteria to qualify for opt-out or renewal of opt-out, the customer may file a complaint with the commission. The commission shall provide notice and an opportunity for a hearing to resolve any dispute.

(K) Revocation. A customer may revoke an opt-out by providing written notice to the utility and commission two to four (2–4) months in advance of the calendar year for which it will become eligible for the utility's demand-side programs' costs and benefits. Any customer revoking an opt-out to participate in demand-side programs will be required to remain in the demand-side program(s) for the number of years over which the cost of that demand-side program(s) is being recovered, or until the cost of their participation in the demand-side program(s) has been recovered.

(L) A customer who participates in demand-side programs initiated after August 1, 2009, shall be required to participate in demand-side programs funding for a period of three (3) years following the last date when the customer received a demand-side incentive or a service. Participation shall be determined based on premise location regardless of the ownership of the premise.

(M) A customer electing not to participate in an electric utility's demand-side programs under this section shall still be allowed to participate in interruptible or curtailable rate schedules or tariffs offered by the electric utility.

(8) Database of Participants.

(A) The electric utility shall maintain a database of participants of all demand-side programs offered by the utility when such demand-side programs offer a monetary incentive to the customer including the following information:

1. The name of the participant, or the names of the principals if for a company;

2. The service property address; and

3. The date of and amount of the monetary incentive received.

(B) Upon request by the commission or staff, the utility shall disclose participant information in subsection (8)(A) to the commission and/or staff.

(9) Collaborative Guidelines.

(A) Utility-Specific Collaboratives. Each electric utility and its stakeholders shall form a utility-specific advisory collaborative for input on the design, implementation, and review of demand-side programs as well as input on the preparation of market potential studies. This collaborative process may take place simultaneously with the collaborative process related to demand-side programs for 4 CSR 240-22. Collaborative meetings are encouraged to occur at least once each calendar quarter. In order to provide appropriate and informed input on the design, implementation, and review of demand-side programs, the stakeholders will be provided drafts of all plans and documents prior to meeting with adequate time to review and provide comments. In addition, all stakeholders will be provided opportunity to inform and suggest agenda items for each meeting and to present presentations and proposals. All participants shall be given a reasonable period of time to propose agenda items and prepare for any presentations.

(B) State-Wide Collaborative.

1. Electric utilities and their stakeholders shall formally establish a state-wide advisory collaborative. The collaborative shall—

A. Develop statewide protocols for evaluation, measurement, and verification of energy efficiency savings, no later than December 31, 2018, and update those protocols annually thereafter;

B. Establish individual working groups to address the creation of the specific deliverables of the collaborative; and

C. Create a semi-annual forum for discussing and resolving statewide policy issues, wherein utilities may share lessons learned from demand-side program planning and implementation, and wherein stakeholders may provide input on how to implement the recommendations of the individual working groups;

D. Explore other opportunities.

2. Within sixty (60) days of the effective date of this rule, commission staff shall file, with the commission, a charter for the statewide advisory collaborative.

3. Collaborative meetings shall occur at least semi-annually. Additional meetings or conference calls will be scheduled as needed. Staff shall schedule the meetings, provide notice of the meetings, and any interested persons may attend such meetings.

(10) Statewide Technical Reference Manual (statewide TRM).

(A) The statewide TRM shall be submitted to the commission for review.

1. The commission may either approve or reject the proposed statewide TRM.

2. If the commission rejects the proposed statewide TRM, stakeholders may propose solutions to address the commission concerns and, the commission may approve the solution(s) that shall be incorporated in the statewide TRM. Stakeholders may submit a revised statewide TRM within ninety (90) days of an order providing direction on the solution(s) to be incorporated in the statewide TRM.

(B) Upon approval of the initial statewide TRM, the commission may begin the process of securing a vendor to provide an electronic, web-based platform that will facilitate annual updates and the tracking of the updates.

1. Funding for the electronic platform and annual updates shall be provided by investor-owned utilities without MEEIA programs through their Public Service Commission assessment and by investor-owned utilities with MEEIA programs through their cost recovery component of a DSIM.

(C) The statewide TRM shall be updated by December 31 of each year following commission approval of the initial statewide TRM.

1. Staff shall be responsible for coordinating the process to update the statewide TRM.

A. No later than July 1 of each year, staff shall convene one (1) or more stakeholder meetings to seek input on revisions to the TRM.

2. Annual updates shall be submitted to the commission for review no later than September 1 of each year.

A. The commission may either approve or reject the proposed revisions no later than October 1 of each year.

B. If the commission rejects the proposed statewide TRM, stakeholders shall propose solutions to address the commission concerns, and the commission may approve the solution(s) that shall be incorporated in the annual update. Stakeholders shall submit a revised statewide TRM within thirty (30) days of an order providing directions on the solution(s) to be incorporated in the annual update.

(D) The commission may consider the appropriateness of using an approved statewide TRM in each utility's application for approval of demand-side programs.

(11) Variances. Upon request and for good cause shown, the commission may grant a variance from any provision of this rule.

AUTHORITY: sections 393.1075.11 and 393.1075.15, RSMo 2016. This rule originally filed as 4 CSR 240-20.094. Original* *rule filed Oct. 4, 2010, effective May 30, 2011. Amended: Filed Dec. 27, 2016, effective Oct. 30, 2017. Moved to 20 CSR 4240-20.094, effective Aug. 28, 2019.*

**Original authority: 393.1075, RSMo 2009.*

20 CSR 4240-20.100 Electric Utility Renewable Energy Standard Requirements

PURPOSE: This rule sets the definitions, structure, operation, and procedures relevant to compliance with the Renewable Energy Standard.

(1) Definitions. For the purpose of this rule—

(A) Calendar year means a period of three hundred sixty-five (365) days (or three hundred sixty-six (366) days for leap years) that includes January 1 of the year and all subsequent days through and including December 31 of the same year;

(B) Co-fire means simultaneously using multiple fuels in a single generating unit to produce electricity;

(C) Commission means the Public Service Commission of the state of Missouri;

(D) Customer-generator means the owner, lessee, or operator of an electric energy generation unit that meets all of the following criteria:

1. Is powered by a renewable energy resource;

2. Is located on premises that are owned, operated, leased, or otherwise controlled by the party as retail account holder and which corresponds to the service address for the retail account;

3. Is interconnected and operates in parallel phase and synchronization with an electric utility and has been approved for interconnection by said electric utility; and

4. Meets all applicable safety, performance, interconnection, and reliability standards of the net metering rule, 4 CSR 240-20.065(1)(C)6. and 4 CSR 240-20.065(1)(C)7.

(E) Division means the Division of Energy, Department of Economic Development;

(F) Electric utility means an electrical corporation as defined in section 386.020, RSMo;

(G) General rate proceeding means a general rate proceeding before the commission where the commission considers all relevant factors that may affect the costs or rates and charges of the electric utility when setting rates;

(H) Green pricing program means a voluntary program that provides an electric utility's retail customers an opportunity to purchase renewable energy or renewable energy credits (RECs);

(I) OPC means the Office of the Public Counsel;

(J) Operational means all of the major components of the on-site solar photovoltaic system have been purchased and installed on the customer generator's premises, and the production of rated net electrical generation has been measured by the utility. If a customer has satisfied all of the System Completion Requirements by June 30 of indicated years, but the electric utility is not able to complete all of the electric utility's steps needed to establish an Operational Date on or before June 30, the rebate rate will be determined as though the Operational Date was June 30. If it is subsequently determined that the customer or the System did not satisfy all Completion Requirements required of the customer on or before June 30, the rebate rate will be determined based on the Operational Date;

(K) PVWatts™ means the site specific data calculator that uses hourly typical meteorological year weather data and a photovoltaic performance model to estimate annual energy production and costs savings for a photovoltaic system;

(L) Rate class means a customer class defined in an electric utility's tariff. Generally, rate classes include Residential, Small General Service, Large General Service, and Large Power Service, but may include additional rate classes. Each rate class includes all customers served under all variations of the rate schedules available to that class;

(M) REC, Renewable Energy Credit, or Renewable Energy Certificate means a tradable certificate, that is either certified by an entity approved as an acceptable authority by the commission or as validated through the commission's approved REC tracking system or a generator's attestation. RECs validated through an attestation must be signed by an authorized individual of the company that owns the renewable energy resource. Such attestation shall contain the name and address of the generator, the type of renewable energy resource technology, and the time and date of the generation. A REC represents that one (1) megawatt-hour of electricity has been generated from renewable energy resources. RECs include, but are not limited to, solar renewable energy credits. A REC expires three (3) years from the date the electricity associated with that REC was generated;

(N) Renewable energy resource(s) means electric energy, produced from the following:

1. Wind;

2. Solar, including solar thermal sources utilized to generate electricity, photovoltaic cells, or photovoltaic panels;

3. Dedicated crops grown for energy production;

4. Cellulosic agricultural residues;

5. Plant residues;

6. Methane from landfills, from agricultural operations or wastewater treatment;

7. Thermal depolymerization or pyrolysis for converting waste material to energy;

8. Clean and untreated wood, such as pallets;

9. Hydropower (not including pumped storage) that does not require a new diversion or impoundment of water and that has generator nameplate ratings of ten (10) megawatts or less;

10. Fuel cells using hydrogen produced by any of the renewable energy technologies in paragraphs 1. through 9. of this subsection; and

11. Other sources of energy not including nuclear that become available after November 4, 2008, and are certified as renewable by rule by the division;

(O) RES or Renewable Energy Standard means sections 393.1025 and 393.1030, RSMo;

(P) RESRAM or Renewable Energy Standard Rate Adjustment Mechanism means a mechanism that allows periodic rate adjustments to recover prudently incurred RES compliance costs and pass-through to customers the benefits of any savings achieved in meeting the requirements of the Renewable Energy Standard;

(Q) RES compliance costs means prudently incurred costs, both capital and expense, directly related to compliance with the Renewable Energy Standard. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the electric utility;

(R) RES portfolio requirements mean the numeric values and other requirements established by section 393.1030.1, RSMo, which are—

1. No less than two percent (2%) in each calendar year 2011 through 2013;

2. No less than five percent (5%) in each calendar year 2014 through 2017;

3. No less than ten percent (10%) in each calendar year 2018 through 2020; and

4. No less than fifteen percent (15%) in each calendar year beginning in 2021.

5. At least two percent (2%) of each RES portfolio requirement listed in this section shall be derived from solar energy. The RES portfolio requirements for solar energy are—

A. No less than four-hundredths percent (0.04%) in each calendar year 2011 through 2013;

B. No less than one-tenth percent (0.1%) in each calendar year 2014 through 2017;

C. No less than two-tenths percent (0.2%) in each calendar year 2018 through 2020; and

D. No less than three-tenths percent (0.3%) in each calendar year beginning in 2021;

(S) The RES revenue requirement means the following:

1. All expensed RES compliance costs (other than taxes and depreciation associated with capital projects) that are included in the electric utility's revenue requirement in the proceeding in which the RESRAM is established, continued, modified, or discontinued; and

2. The costs (i.e., the return, taxes, and depreciation) of any capital projects whose primary purpose is to permit the electric utility to comply with any RES requirement. The costs of such capital projects shall be those identified on the electric utility's books and records as of the last day of the test year, as updated, utilized in the proceeding in which the RESRAM is established, continued, modified, or discontinued;

(T) Solar renewable energy credit or S-REC means a REC created by generation of electric energy from solar thermal sources, photovoltaic cells, and photovoltaic panels;

(U) Staff means all commission employees, except the secretary to the commission, general counsel, technical advisory staff as defined by section 386.135, RSMo, hearing officer, or administrative or regulatory law judge;

(V) Standard Test Conditions means solar incidence of one (1) kilowatt (kW) per square meter and a cell or panel temperature of twenty-five degrees centigrade (25 °C) for measuring the capability of solar electrical generating equipment;

(W) Total retail electric sales, or total retail electric energy usage, means the megawatt-hours (MWh) of electricity delivered in a specified time period by an electric utility to its Missouri retail customers as reflected in the retail customers' monthly billing statements; and

(X) Utility renewable energy resources mean those renewable energy resources that are owned, controlled, or purchased by the electric utility.

(2) Requirements. Pursuant to the provisions of this rule and sections 393.1025 and 393.1030, RSMo, all electric utilities must generate or purchase RECs and S-RECs associated with electricity from renewable energy resources in sufficient quantity to meet the RES portfolio requirements (renewable and solar) on a calendar year basis. Utility renewable energy resources utilized for compliance with this rule must include the RECs or S-RECs associated with the generation. The RES portfolio requirements are based on total retail electric sales of the electric utility. The requirements set forth in this rule shall not preclude an electric utility from recovering all of its prudently incurred investment and costs incurred for renewable energy resources that exceed the requirements or limits of this rule but are consistent with the prudent implementation of any resource acquisition strategy the electric utility developed in compliance with 4 CSR 240-22, Electric Utility Resource Planning. RECs or S-RECs produced from these additional renewable energy resources may count toward the RES portfolio requirements.

(A) Reserved*

(B) The amount of renewable energy resources or RECs that can be counted towards meeting the RES portfolio requirements are as follows:

1. If the facility generating the renewable energy resource is located in Missouri, the allowed amount is the kilowatt-hours (kWhs) generated by the applicable generating facility, multiplied by one and twenty-five hundredths (1.25) to effectuate the credit pursuant to section 393.1030.1, RSMo and subsection (3)(G) of this rule; and

2. Reserved*;

3. RECs created by the operation of customer-generator facilities and acquired by the Missouri electric utility shall qualify for RES compliance if the customer-generator is a Missouri electric energy retail customer, regardless of the amount of energy the customer-generator provides to the associated retail electric provider through net metering in accordance with 4 CSR 240-20.065, Net Metering. RECs are created by the operation of the customer-generator facility, even if a significant amount or the total amount of electrical energy is consumed on-site at the location of the customer-generator.

(C) If compliance with the RES portfolio requirements would cause the retail rates of an electric utility to increase on average in excess of one percent (1%) as calculated per section (5) of this rule, then compliance with those mandates shall be limited so that the cost of them would not cause retail rates of the electric utility to increase on average one percent (1%) as calculated per section (5) of this rule.

(D) If an electric utility is not required to meet the RES portfolio requirements in a calendar year, because doing so would cause retail rates to increase on average in excess of one percent (1%) as calculated per section (5) of this rule, then the RES portfolio requirement for solar energy shall be no less than two percent (2%) of the renewable energy resources that can be acquired subject to the one percent (1%) average retail rates limit as calculated per section (5) of this rule.

(E) If an electric utility intends to accept proposals for renewable energy resources to be owned by the electric utility or an affiliate of the electric utility, it shall comply with the necessary requirements of 4 CSR 240-20.015, Affiliate Transactions.

(3) RECs and S-RECs. Subject to the requirements of section (2) of this rule, RECs and S-RECs shall be utilized to satisfy the RES requirements of this rule. S-RECs shall be utilized to comply with the RES portfolio requirements for solar energy and may be utilized to comply with the RES portfolio requirements for other renewable energy resources.

(A) The REC or S-REC creation is linked to the associated renewable energy resource. For purposes of retaining RECs or S-RECs, the utility, person, or entity responsible for creation of the REC or S-REC must maintain verifiable records that prove the creation date. The electric utility shall comply with the requirement of this subsection through the registration of the REC in the commission's approved REC tracking system.

(B) A REC may only be used once to comply with this rule. RECs or S-RECs used to comply with this rule may not also be used to satisfy any other nonfederal renewable energy standard or requirement. Electric utilities may not use RECs or S-RECs retired under a green pricing program to comply with this rule. RECs and S-RECs may be used to comply with the RES portfolio requirements of this rule for a calendar year in which it expired so long as it was valid at any time in that year.

(C) Customer-generators own the RECs and S-RECs associated with their customer-generated net-metered renewable energy resources; however, if a customer generator receives a solar rebate, the customer-generator transfers to the electric utility all right, title, and interest in and to the RECs associated with the new or expanded solar electric system that qualifies the customer-generator for the solar rebate for a period of ten (10) years from the date the electric utility confirms the customer-generator's solar electric system is operational.

1. All standard offer contracts between electric utilities and the owners of net-metered renewable resources that are entered into after the effective date of these rules shall clearly specify who owns the RECs or S-RECs associated with the energy generated by the net-metered generation resource, and when the ownership will change, if it will.

2. Electric metering associated with net-metered renewable resources shall meet the meter accuracy and testing requirements of 4 CSR 240-10.030, Standards of Quality.

(D) RECs that are generated with fuel cell energy using hydrogen derived from a renewable energy resource are eligible for compliance purposes only to the extent that the energy used to generate the hydrogen did not create RECs.

(E) If an eligible renewable energy fuel source is co-fired with an ineligible fuel source, only the proportion of the electrical energy output associated with the eligible renewable energy fuel source shall be permitted to count toward compliance with the RES portfolio requirements. For co-fired generation of electricity, the renewable energy resources shall be determined by multiplying the electricity output by the direct proportion of the as-fired British thermal unit (BTU) content of the fuel burned that is a source of renewable energy resources as defined in this rule to the as-fired BTU content of the total fuel burned.

(F) All electric utilities shall use a commission designated common central third-party registry for REC accounting for RES portfolio requirements, unless otherwise ordered for good cause shown.

(G) RECs created by the generation of electricity by a renewable energy resource physically located in the state of Missouri shall count as one and twenty-five hundredths (1.25) RECs for purposes of compliance with this rule. This additional credit shall not be tracked in the tracking systems specified in subsection (F) of this section. This additional credit of twenty-five hundredths (0.25) shall be recognized when the electric utility files its annual compliance report in accordance with section (7) of this rule.

(H) RECs created by the generation of electricity at a facility that subsequently fails to meet the requirements for renewable energy resources are valid if they were created before the date at which the facility is decertified.

(I) Electric utilities required to comply with this rule may purchase or sell RECs, either bilaterally or in any open market system, inside or outside the state, without prior commission approval.

(J) For compliance purposes, electric utilities shall retire RECs in sufficient quantities to meet the RES portfolio requirements of this rule. The RECs shall be retired during the calendar year for which compliance is sought. Electric utilities may retire RECs from January 1 through April 15 of the following year, following the calendar year for which compliance is being sought and designate those retired RECs as counting towards the requirements of that previous calendar year. Any RECs retired in this manner shall be specifically annotated in the registry designated in accordance with subsection (F) of this section and the annual compliance report filed in accordance with section (7) of this rule. RECs retired from January 1 through April 15 of the following year, to be counted towards compliance for the previous calendar year in accordance with this subsection shall not exceed ten percent (10%) of the total RECs necessary to be retired for compliance for that calendar year.

(K) RECs may be aggregated with other RECs for compliance purposes. RECs shall be issued in whole increments. Any fractional RECs, aggregated or non-aggregated, remaining after certificate issuance will be carried forward to the next reporting period for the specific facility(ies). REC aggregation may be performed by electric utilities, customer-generators, or others.

(L) Fractional RECs may be aggregated with other fractional RECs and utilized for compliance with this rule.

(4) Solar Rebate. Pursuant to sections 393.1030 and 393.1670, RSMo, and this rule, electric utilities shall include in their tariffs a provision regarding retail account holder rebates for solar electric systems. These rebates shall be available to Missouri electric utility retail account holders who install new or expanded solar electric systems comprised of photovoltaic cells or photovoltaic panels. As used in this section, customer means retail account holder.

(A) The retail account holder must be an active account on the electric utility's system and in good payment standing.

(B) The solar electric system must be permanently installed on the account holder's premises. As installed, the solar electric system shall be situated in a location where a minimum of eighty-five percent (85%) of the solar resource is available to the system as verified by the customer or the customer's installer at the time of installation.

(C) The installed solar electric system must remain in place on the account holder's (customer-generator's) premises for ten (10) years unless determined otherwise by the commission.

(D) Solar electric systems installed by retail account holders must consist of equipment that is commercially available and factory new when installed on the original account holder's premises, and the principal system components (i.e., photovoltaic modules and inverters) shall be covered by a functional warranty from the manufacturer for a minimum period of ten (10) years, unless determined otherwise by the commission, with the exception of solar battery components. Rebuilt, used, or refurbished equipment is not eligible to receive the rebate.

1. Solar rebates made available prior to January 1, 2019, shall be limited to twenty-five (25) kW for any applicable retail account. Retail accounts which have been awarded rebates for an aggregate of less than twenty-five (25) kW shall qualify to apply for rebates for system expansions up to an aggregate of twenty-five (25) kW. Systems greater than twenty-five (25) kW but less than one hundred (100) kW in size shall be eligible for a solar rebate up to the twenty-five (25) kW limit of this section.

2. Solar rebates for systems that become operational after January 1, 2019 shall be available for new or expanded solar electric systems up to twenty-five (25) kW for residential customers and one hundred and fifty (150) kW for non-residential customers. Residential net-metered or interconnected solar electric systems greater than twenty-five (25) kW but less than one hundred (100) kW in size shall be eligible for a solar rebate up to the twenty-five (25) kW limit of this section. Customers shall be eligible for rebates on new or expanded systems for the increment of new or expanded capacity and not for capacity on which rebates offered under any other provision of law have previously been paid, up to the system kilowatt limits outlined in this section.

(E) Solar electric systems which are less than 100 kW in size shall meet all requirements of 4 CSR 240-20.065, Net Metering, or all the requirements a customer-generator must meet under 4 CSR 240-20.100(1)(D).

(F) The electric utility may physically audit customer-generator owned solar electric systems for which it has paid a solar rebate pursuant to this section, at any reasonable time, with prior notice of at least three (3) business days provided to the retail account holder.

(G) For the purpose of determining the amount of solar rebate, the solar electric system wattage rating shall be established as the direct current wattage rating provided by the original manufacturer with respect to standard test conditions.

(H) Standard Offer Contracts.

1. The electric utility may, at its discretion, offer a standard contract for the purchase of S-RECs created by the customer-generator's installed solar electric system.

2. If the electric utility chooses to offer a standard offer contract, the electric utility shall file tariff sheets detailing the provision of the contract no later than November 1 each year for the following compliance year. Workpapers documenting the purchase prices shall be submitted with the tariff filing.

(I) No customer-generator is required by this rule to sell any or all S-RECs to the electric utility; however, a condition of receiving a solar rebate from an electric utility is that all right, title, and interest in and to the RECs associated with the new or expanded solar electric system that qualifies the customer-generator for the solar rebate is transferred to the electric utility paying the rebate for a period of ten (10) years from the date the electric utility confirms the customer-generator's solar electric system is operational.

(J) Electric utilities that have acquired S-RECs under a one- (1-) time lump sum payment in accordance with subsection (H) of this section or as a result of the solar rebate S-RECs transferred through the solar rebate may continue to account for purchased S-RECs even if the owner of the solar electric system ceases to operate the system or the system is decertified as a renewable energy resource. S-RECs originated under this subsection shall only be utilized by the original purchasing utility for compliance with this rule. S-RECs originated under this subsection shall not be sold or traded.

(K) Electric utilities that have purchased S-RECs under a one- (1-) time lump sum payment or otherwise have acquired right, title, and interest in and to S-RECs associated with solar rebates annually shall estimate, using PVWatts, or actually measure the S-RECs generated from the customer-generator's operational solar electric system.

(L) The electric utility shall provide the solar rebate payment to qualified customer-generators within thirty (30) days of confirming the customer-generator's solar electric system is operational.

(M) Any future payment of valid solar rebate applications, queued for payment prior to August 28, 2018, shall not count toward the annual or aggregate limits prescribed in section 393.1670(1), RSMo.

(N) For electric utilities with less than two hundred thousand (200,000) Missouri retail customers—

1. Solar rebate payments made prior to January 1, 2019 shall be limited to twenty-five (25) kW for both residential and non-residential customers; and

2. In the event the limit has been reached, the electric utility shall continue to process and pay solar rebates until the electric utility meets or exceeds the retail rate impact limits of section (5) of this rule. However, these solar rebates shall be limited to twenty-five (25) kW for both residential and non-residential customers.

(O) An electric utility may, through its tariff, require applications for solar rebates to be submitted up to one hundred eighty-two (182) days prior to the June 30 operational dates. The electric utility will pay the pre-June 30 rebate amount as defined in this subsection to customer-generators who comply with the submission and system operational requirements on or before June 30 of the following year. Customer-generators that fail to meet the submission or system operational requirements on or before the June 30 date will receive the post-June 30 rebate amount if the electric utility confirms their solar electric systems are operational within one (1) year of their application. If a customer has satisfied all of the System Completion Requirements by June 30 of indicated years, but the electric utility is not able to complete all of the electric utility's steps needed to establish an Operational Date on or before June 30, the rebate rate will be determined as though the Operational Date was June 30. If it is subsequently determined that the customer or the System did not satisfy all Completion Requirements required of the customer on or before June 30, the rebate rate will be determined based on the Operational Date.

(P) Unless the commission orders otherwise, if the electric utility meets or exceeds the retail rate impact limits of section (5) of this rule, the solar rebates shall be paid as determined by the solar system operational date. Any solar rebate applications that are not honored in a particular calendar year due to the requirements of this subsection shall be considered in the following calendar year.

(Q) An electric utility shall maintain on its website, current information related to—

1. The electric utility's solar rebate application and review processes, including standards for determining application eligibility;

2. The solar rebate amount associated with pending applications that have been submitted, but not yet reviewed;

3. The current level of solar rebate payments; and

4. The rebate amount associated with applications that are approved, but where the solar electric system is not yet operational.

(5) Retail Rate Impact.

(A) The retail rate impact (RRI), as calculated in subsection (5)(B), may not exceed one percent (1%) for prudent costs of renewable energy resources directly attributable to RES compliance. The retail rate impact shall be calculated annually on an incremental basis for each planning year based on procurement or development of renewable energy resources averaged over the succeeding ten- (10-) year period. The retail rate impact shall exclude renewable energy resources owned or under contract prior to September 30, 2010.

(B) The RES retail rate impact shall be determined by subtracting the total retail revenue requirement incorporating an incremental non-renewable generation and purchased power portfolio from the total retail revenue requirement including an incremental RES-compliant generation and purchased power portfolio.

1. The non-renewable generation and purchased power portfolio shall be determined by adding, to the utility's existing generation and purchased power resource portfolio excluding all renewable resources, additional non-renewable resources sufficient to meet the utility's needs on a least-cost basis for the next ten (10) years.

2. The RES-compliant portfolio shall be determined by adding to the utility's existing generation and purchased power resource portfolio an amount of least cost renewable resources sufficient to achieve the portfolio requirements set forth in section (2) of this rule and an amount of least-cost non-renewable resources, the combination of which is sufficient to meet the utility's needs for the next ten (10) years.

3. The cost of the RES-compliant portfolio shall also include the positive or negative cumulative carry-forward amount as determined in subsection (5)(G).

4. Assumptions regarding projected renewable energy resource additions will utilize the most recent electric utility resource planning analysis. These comparisons will be conducted utilizing incremental revenue requirement for new renewable energy resources, less the avoided cost for non-renewable energy resources due to the addition of renewable energy resources. Such avoided costs shall be limited to those that may be included in a utility's revenue requirement for setting rates In addition, the projected impact on revenue requirements by non-renewable energy resources shall include the expected value of greenhouse gas emissions compliance costs, assuming that such costs are made at the expected value of the cost per ton of greenhouse gas emissions allowances, cost per ton of a greenhouse gas emissions tax (e.g., a carbon tax), or the cost per ton of greenhouse gas emissions reductions for any greenhouse gas emission reduction technology that is applicable to the utility's generation portfolio, whichever is lower. Calculations of the expected value of costs associated with greenhouse gas emissions shall be derived by applying the probability of the occurrence of future greenhouse gas regulations to expected level(s) of costs per ton associated with those regulations over the next ten (10) years. The impact on revenue requirements by non-renewable energy resources shall also include consideration of environmental risks other than those related to regulation or greenhouse gases. Any costs included to reflect consideration of such risks shall be limited to those that may be included in a utility's revenue requirement for setting rates. Any variables utilized in the modeling shall be consistent with values established in prior rate proceedings, electric utility resource planning filings, or RES compliance plans, unless specific justification is provided for deviations. In no event shall the calculation of rate impact double count the cost of fuel or environmental compliance cost savings.

(C) Solar rebates payments made during any calendar year in accordance with section (4) of this rule shall be included in the cost of generation from renewable energy resources.

(D) For purposes of the determination in accordance with subsection (B) of this section, if the revenue requirement including the RES-compliant resource mix, averaged over the ten- (10-) year period, exceeds the revenue requirement that includes the non-renewable resource mix by more than one percent (1%), the utility shall adjust downward the proportion of renewable resources so that the average annual revenue requirement differential does not exceed one percent (1%). In making this adjustment, the solar requirement shall be in accordance with subsection (2)(D) of this rule. Prudently incurred costs to comply with the RES portfolio requirements, and passing this rate impact test, may be recovered in accordance with section (6) of this rule or through a rate proceeding outside or in a general rate case. When adjusting downward the proportion of renewable energy resources, in accordance with this subsection, the utility shall give first priority to reducing or eliminating the amount of RECs not associated with electricity delivered to Missouri customers.

(E) Costs or benefits attributed to compliance with a federal renewable energy standard or portfolio requirement shall be considered as part of compliance with the Missouri RES if they would otherwise qualify under the Missouri RES without regard to the federal requirements.

(F) If the electric utility determines the maximum average retail rate increase provided for in section (5) will be reached in any calendar year, the electric utility may cease paying rebates to the extent necessary to avoid exceeding the maximum average retail rate increase by filing a request with the commission, at least sixty (60) days in advance, to suspend the solar rebate provisions in its tariff for the remainder of the calendar year.

1. The filing with the commission to suspend the electric corporation's solar rebate tariff provision shall include:

A. Its calculation reflecting that the maximum average retail rate increase will be reached with supporting documentation;

B. A proposed procedural schedule; and

C. A description of the process that it will use to cease or conclude the solar rebate payments to solar customers if the commission suspends its solar rebate tariff provision.

2. The commission shall rule on the suspension filing within sixty (60) days of the date it is filed. If the commission determines the maximum average retail rate increase will be reached, the commission shall suspend solar rebate payments. The commission will not suspend payment of solar rebates unless it expressly finds that the electric utility has accurately calculated the retail rate impact in the manner prescribed by this section (5).

3. The electric utility shall continue to process and pay applicable solar rebates until a final commission ruling.

A. If continuing to pay solar rebates causes the electric utility to exceed the maximum average retail rate increase, the excess payments shall not be considered to have been imprudently incurred for that reason.

(G) The utility shall calculate for each actual compliance year an annual carry-forward amount, illustration included herein as Attachment A. This amount shall be calculated as the positive or negative difference between the actual costs of RES compliance and an amount equal to the one percent (1%) cap, as calculated in subsection (5)(B), for the non-renewable generation and purchased power portfolio from its most recent annual RES compliance plan filed pursuant to subsection (7)(B) of this rule. The positive or negative cumulative carry-forward amount shall be calculated by accumulating the annual positive or negative annual carry-forward amounts. The initial cumulative carry-forward amount shall be equal to the sum of the annual carry-forward amounts for the period January 1, 2015, through December 31, 2015. Any annual carry-forward amounts shall be based on the revenue requirements analysis included in the utility's Annual RES Compliance Plan filed pursuant to subsection (8)(B) for each respective year. The positive or negative cumulative carry-forward amount shall be included in the cost of the RES-compliant portfolio for purposes of calculating the retail rate impact, as calculated in subsection (5)(B). Nothing in this subsection shall authorize recovery in excess of the one percent (1%) cap, as defined in subsection (5)(B).

(H) If in reliance on a calculation of the RRI as provided for herein, an electric utility commits to fund a utility-owned renewable energy resource, or contracts to acquire energy or capacity from a renewable energy resource that, based on the relied-upon RRI calculation would not cause the electric utility to exceed such RRI, then the prudently incurred costs of such renewable energy resource and such energy and capacity shall constitute RES compliance costs even if including such costs in later calculations will cause the electric utility to exceed the RRI calculated at a later time. To the extent the prudently incurred costs of a utility-owned renewable energy resource, or contracted for energy or capacity from a renewable energy resource, cause an electric utility to exceed the RRI calculated at a later time, such excess sum shall be included in the determination of the carry-forward amount in accordance with subsection (5)(G).

(I) Not withstanding anything in subsection (5)(H), until June 30, 2020, if the maximum average retail rate increase, as calculated pursuant to subsection (5)(B) would be less than or equal to one percent (1%) if an electric utility's investment in solar-related projects initiated, owned, or operated by the electric utility is ignored for purposes of calculating the increase, then additional solar rebates shall be made available and included in rates in an amount up to the amount that would produce a retail rate increase equal to the difference between a one percent (1%) retail rate increase and the retail rate increase calculated when ignoring an electric utility's investment in solar projects initiated, owned, or operated by the electric utility.

(J) Each electric utility shall calculate its actual calendar year RRI each year and shall file those calculations as part of its annual RES compliance plan. The electric utility may designate all or part of those calculations as highly confidential, proprietary, or public as appropriate under the commission's rules.

(6) Cost Recovery and Pass-through of Benefits. An electric utility outside or in a general rate proceeding may file an application and rate schedules with the commission to establish, continue, modify, or discontinue a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) that shall allow for the adjustment of its rates and charges to provide for recovery of prudently incurred costs or pass-through of benefits received as a result of compliance with the RES; provided that the average annual impact on retail customer rates does not exceed one percent (1%) over a ten- (10-) year period as set out in subsections (5)(A), (B) and (G). In all RESRAM applications, the increase in electric utility revenue requirements shall be calculated as the amount of additional RES compliance costs incurred since the electric utility's last RESRAM application or general rate proceeding, net of any reduction in RES compliance costs included in the electric utility's prior RESRAM application or general rate case, and any new RES compliance benefits.

(A) For all RESRAM filings, except the initial filings by the electric utility, if the actual increase in utility revenue requirement is less than two percent (2%), subsection (B) of this section shall be utilized. If the actual increase in utility revenue requirement is equal to or greater than two percent (2%), subsection (C) of this section shall be utilized. For the initial filing by the electric utility in accordance with this section, subsection (B) of this section shall be utilized as well, except that the staff, and individuals or entities granted intervention by the commission, may file a report or comments no later than one hundred twenty (120) days after the electric utility files its application and rate schedules to establish a RESRAM.

1. The pass-through of benefits has no single-year cap or limit.

2. Any party in a rate proceeding in which a RESRAM is in effect or proposed may seek to continue as is, modify, or oppose the RESRAM. The commission shall approve, modify, or reject such applications and rate schedules to establish a RESRAM only after providing the opportunity for an evidentiary hearing.

3. If the electric utility incurs costs in complying with the RES that exceed the one percent (1%) rate limit determined in accordance with section (5) of this rule for any year, those excess costs may be carried forward to future years for cost recovery permitted under this rule. Any costs carried forward shall have a carrying cost applied to them monthly equal to the interest on those carried forward costs calculated at the electric utility's short-term borrowing rate. These carried forward costs plus accrued carrying costs plus additional annual costs remain subject to the one percent (1%) rate limit for any subsequent years. In any calendar year that costs from a previous compliance year are carried

forward, the carried forward costs will be considered for cost recovery prior to any new costs for the current calendar year.

4. For ownership investments in eligible renewable energy technologies in a RESRAM application, the electric utility shall be entitled to a rate of return equal to the electric utility's most recent authorized rate of return on rate base. Recovery of the rate of return for investment in renewable energy technologies in a RESRAM application is subject to the one percent (1%) limit specified in section (5) of this rule.

5. Upon the filing of proposed rate schedules with the commission seeking to recover costs or pass-through benefits of RES compliance, the commission will provide general notice of the filing.

6. The electric utility shall provide the following notices to its customers, with such notices to be approved by the commission in accordance with paragraph 7. of this subsection before the notices are sent to customers:

A. An initial, one- (1-) time notice to all potentially affected customers, such notice being sent to customers no later than when customers will receive their first bill that includes a RESRAM, explaining the utility's RES compliance and identifying the statutory authority under which it is implementing a RESRAM;

B. An annual notice to affected customers each year that a RESRAM is in effect explaining the continuation of its RESRAM and RES compliance; and

C. A RESRAM line item on all customer bills, which informs the customers of the presence and amount of the RESRAM charge.

7. Along with the electric utility's filing of proposed rate schedules to establish a RESRAM, the utility shall file the following items with the commission for approval or rejection, and the OPC may, within ten (10) days of the utility's filing of this information, submit comments regarding these notices to the commission:

A. An example of the notice required by subparagraph (A)6.A. of this section;

B. An example of the notice required by subparagraph (A)6.B. of this section; and

C. An example customer bill showing how the RESRAM will be described on affected customers' bills in accordance with subparagraph (A)6.C. of this section.

8. An electric utility may effectuate a change in its RESRAM no more often than one (1) time during any calendar year, not including changes as a result of paragraph 11. of this subsection.

9. Submission of Surveillance Monitoring Reports. Each electric utility with an approved RESRAM shall submit to staff, OPC, and parties approved by the commission, a Surveillance Monitoring Report. The form of the Surveillance Monitoring Report is included herein.

A. The Surveillance Monitoring Report shall be submitted within fifteen (15) days of the electric utility's next scheduled United States Securities and Exchange Commission (SEC) 10-Q or 10-K filing with the initial submission within fifteen (15) days of the electric utility's next scheduled SEC 10-Q or 10-K filing following the effective date of the commission order establishing the RESRAM.

B. If the electric utility also has an approved fuel rate adjustment mechanism or environmental cost recovery mechanism (ECRM), the electric utility shall submit a single Surveillance Monitoring Report for the RESRAM, ECRM, the fuel rate adjustment mechanism, or any combination of the three (3). The electric utility shall designate on the single Surveillance Monitoring Report whether the submission is for RESRAM, ECRM, fuel rate adjustment mechanism, or any combination of the three (3).

C. Upon a finding that a utility has knowingly or recklessly provided materially false or inaccurate information to the commission regarding the surveillance data prescribed in this paragraph, after notice and an opportunity for a hearing, the commission may suspend its RESRAM or order other appropriate remedies as provided by law.

10. The RESRAM charge will be calculated as a percentage of the customer's energy charge for the applicable billing period.

11. Commission approval of proposed rate schedules, to establish or modify a RESRAM, shall in no way be binding upon the commission in determining the ratemaking treatment to be applied to RES compliance costs during a subsequent general rate proceeding when the commission may undertake to review the prudence of such costs. If the commission disallows, during a subsequent general rate proceeding, recovery of RES compliance costs previously in a RESRAM, or pass-through of benefits previously in a RESRAM, the electric utility shall offset its RESRAM in the future as necessary to recognize and account for any such costs or benefits. The offset amount shall include a calculation of interest at the electric utility's short-term borrowing rate as calculated in subparagraph (A)26.A. of this section. The RESRAM offset will be designed to reconcile such disallowed costs or benefits within the six- (6-) month period immediately subsequent to any commission order regarding such disallowance.

12. At the end of each twelve- (12-) month period that a RESRAM is in effect, the electric utility shall reconcile the differences between the revenues resulting from the RESRAM and the pretax revenues as found by the commission for that period and shall submit the reconciliation to the commission with its next sequential proposed rate schedules for RESRAM continuation or modification.

13. An electric utility that has implemented a RESRAM shall file revised RESRAM rate schedules to reset the RESRAM charge to zero (0) when new base rates and charges become effective following a commission report and order establishing customer rates in a general rate proceeding that incorporates RES compliance costs or benefits previously reflected in a RESRAM in the utility's base rates. If an over- or under-recovery of RESRAM revenues or over- or under-pass-through of RESRAM benefits exists after the RESRAM charge has been reset to zero (0), that amount of over- or under-recovery, or over- or under-pass-through, shall be tracked in an account and considered in the next RESRAM filing of the electric utility.

14. Upon the inclusion of RES compliance cost or benefit pass-through previously reflected in a RESRAM into an electric utility's base rates, the electric utility shall immediately thereafter reconcile any previously unreconciled RESRAM revenues or RESRAM benefits and track them as necessary to ensure that revenues or pass-through benefits resulting from the RESRAM match, as closely as possible, the appropriate pretax revenues or pass-through benefits as found by the commission for that period.

15. In addition to the information required by subsection (B) or (C) of this section, the electric utility shall also provide the following information when it files proposed rate schedules with the commission seeking to establish, modify, or reconcile a RESRAM:

A. A description of all information posted on the utility's website regarding the RESRAM; and

B. A description of all instructions provided to personnel at the utility's call center regarding how those personnel should respond to calls pertaining to the RESRAM.

16. RES compliance costs shall only be recovered through a RESRAM or as part of a general rate proceeding and shall not be considered for cost recovery through an environmental cost recovery mechanism, fuel adjustment clause, or interim energy charge.

17. Pre-existing adjustment mechanisms, tariffs, and regulatory plans. The provisions of this rule shall not affect—

A. Any adjustment mechanism, rate schedule, tariff, incentive plan, or other ratemaking mechanism that was approved by the commission and in effect prior to September 30, 2010; and

B. Any experimental regulatory plan that was approved by the commission and in effect prior to September 30, 2010; and

C. The commission's reports and orders in file numbers ET-2014-0059, ET-2014-0071, and ET-2014-0085.

18. Each electric utility with a RESRAM shall submit, with an affidavit attesting to the veracity of the information, the following information on a monthly basis to the manager of the auditing unit of the commission and to OPC. The information shall be submitted to the manager of the auditing department through the electronic filing and information system (EFIS). The following information shall be aggregated by month and supplied no later than sixty (60) days after the end of each month when the RESRAM is in effect. The first submission shall be made within sixty (60) days after the end of the first complete month after the RESRAM goes into effect. It shall contain, at a minimum—

A. The revenues billed pursuant to the RESRAM by rate class and voltage level, as applicable;

B. The revenues billed through the electric utility's base rate allowance by rate class and voltage level;

C. All significant factors that have affected the level of RESRAM revenues along with workpapers documenting these significant factors;

D. The difference, by rate class and voltage level, as applicable, between the total billed RESRAM revenues and the projected RESRAM revenues;

E. Any additional information the commission orders be provided; and

F. To the extent any of the requested information outlined above is provided in response to another section, the information only needs to be provided once.

19. Information required to be filed with the commission or submitted to the manager of the auditing unit of the commission and to OPC in this section shall also be, in the same format, served on or submitted to any party to the related rate proceeding in which the RESRAM was approved by the commission, periodic adjustment proceeding, prudence review, or general rate case to modify, continue, or discontinue the same RESRAM, pursuant to the procedures in 4 CSR 240-2.135 for handling confidential information, including any commission order issued thereunder.

20. A person or entity granted intervention in a rate proceeding in which a RESRAM is approved by the commission shall be a party to any subsequent related periodic adjustment proceeding or prudence review, without the necessity of applying to the commission for intervention; and the commission shall issue an order identifying them. In any subsequent general rate proceeding, such person or entity must seek and be granted status as an intervenor to be a party to that case. Affidavits, testimony, information, reports, and workpapers to be filed or submitted in connection with a subsequent related periodic adjustment proceeding, prudence review, or general rate case to modify, continue, or discontinue the same RESRAM shall be served on or submitted to all parties from the prior related rate proceeding and on all parties from any subsequent related periodic adjustment proceeding, prudence review, or general rate case to modify, continue, or discontinue the same RESRAM, concurrently with filing the same with the commission or submitting the same to the manager of the auditing unit of the commission and OPC, pursuant to the procedures in 4 CSR 240-2.135 for handling confidential information, including any commission order issued thereunder.

21. A person or entity not a party to the rate proceeding in which the commission approves a RESRAM may timely apply to the commission for intervention, pursuant to sections 4 CSR 240-2.075(2) through (4) of the commission's rule on intervention, respecting any related subsequent periodic adjustment proceeding, or prudence review, or, pursuant to sections 4 CSR 240-2.075(1) through (5), respecting any subsequent general rate case to modify, continue, or discontinue the same RESRAM. If no party to a subsequent periodic adjustment proceeding or prudence review objects within ten (10) days of the filing of an application for intervention, the applicant shall be deemed as having been granted intervention without a specific commission order granting intervention, unless, within the above-referenced ten- (10-) day period, the commission denies the application for intervention on its own motion. If an objection to the application for intervention is filed on or before the end of the above-referenced ten- (10-) day period, the commission shall rule on the application and the objection within ten (10) days of the filing of the objection.

22. The results of discovery from a rate proceeding where the commission may approve, modify, reject, continue, or discontinue a RESRAM, or from any subsequent periodic adjustment proceeding or prudence review relating to the same RESRAM, may be used without a party resubmitting the same discovery requests (data requests, interrogatories, requests for production, requests for admission, or depositions) in the subsequent proceeding to parties that produced the discovery in the prior proceeding, subject to a ruling by the commission concerning any evidentiary objection made in the subsequent proceeding.

23. If a party which submitted data requests relating to a proposed RESRAM in the rate proceeding where the RESRAM was established or in any subsequent related periodic adjustment proceeding or prudence review wants the responding party to whom the prior data requests were submitted to supplement or update that responding party's prior responses for possible use in a subsequent related periodic adjustment proceeding, prudence review, or general rate case to modify, continue, or discontinue the same RESRAM, the party which previously submitted the data requests shall submit an additional data request to the responding party to whom the data requests were previously submitted which clearly identifies the particular data requests to be supplemented or updated and the particular period to be covered by the updated response. A responding party to a request to supplement or update shall supplement or update a data request response from a related rate proceeding where a RESRAM was established, reviewed for prudence, modified, continued, or discontinued, if the responding party has learned or subsequently learns that the data request response is in some material respect incomplete or incorrect.

24. Each rate proceeding where commission establishment, continuation, modification, or discontinuation of a RESRAM is the sole issue shall comprise a separate case. The same procedures for handling confidential information shall apply, pursuant to 4 CSR 240-2.135, as in the immediately preceding RESRAM case for the particular electric utility, unless otherwise directed by the commission on its own motion or as requested by a party and directed by the commission.

25. In addressing certain discovery matters and the provision of certain information by electric utilities, this rule is not intended to restrict the discovery rights of any party.

26. Prudence reviews respecting a RESRAM. A prudence review of the costs subject to the RESRAM shall be conducted no less frequently than at intervals established in the rate proceeding in which the RESRAM is established.

A. All amounts ordered refunded by the commission shall include interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis for each month the RESRAM rate is in effect, equal to the weighted average interest rate paid by the electric utility on short-term debt for that calendar month. This rate shall then be applied to a simple average of the same month's beginning and ending cumulative RESRAM over-collection or under-collection balance. Each month's accumulated interest shall be included in the RESRAM over-collection or under-collection balances on an ongoing basis.

B. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred eighty (180) days after the staff initiates its prudence audit. The staff shall file notice within ten (10) days of starting its prudence audit. The commission shall issue an order not later than two hundred ten (210) days after the staff commences its prudence audit if no party to the proceeding in which the prudence audit is occurring files, within one hundred ninety

(190) days of the staff's commencement of its prudence audit, a request for a hearing.

(I) If the staff, OPC, or other party auditing the RESRAM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's RESRAM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information shall timely file a motion to compel with the commission. While the commission is considering the motion to compel, the processing time line shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing time line. For good cause shown the commission may further suspend this time line.

(II) If the time line is extended due to an electric utility's failure to timely provide sufficient responses to discovery and a refund is due to the customers, the electric utility shall refund all imprudently incurred costs plus interest at the electric utility's short-term borrowing rate. The interest shall be calculated on a monthly basis in the same manner as described in subparagraph (A)26.A. of this section.

(B) RESRAM filing requirements for less than two percent (2%) actual increase in utility revenue requirements.

1. When an electric utility files proposed rate schedules pursuant to sections 393.1020 and 393.1030, RSMo, and the provisions of this rule, the commission staff shall conduct an examination of the proposed RESRAM.

2. The staff of the commission shall examine and analyze the information submitted by the electric utility to determine if the proposed RESRAM is in accordance with provisions of this rule and the statutes governing the RES and shall submit a report regarding its examination to the commission not later than sixty (60) days after the electric utility files its proposed rate schedules.

3. The commission may hold a hearing on the proposed rate schedules and shall issue an order to become effective not later than one hundred twenty (120) days after the electric utility files the proposed rate schedules.

4. If the commission finds that the proposed rate schedules or substitute filed rate schedules comply with the applicable requirements, the commission shall enter an order authorizing the electric utility to utilize said RESRAM rate schedules with an appropriate effective date, as determined by the commission.

5. At the time an electric utility files proposed rate schedules with the commission seeking to establish, modify, or reconcile a RESRAM, it shall submit its supporting documentation regarding the calculation of the proposed RESRAM and shall serve the OPC with a copy of its proposed rate schedules and its supporting documentation. The utility's supporting documentation shall include workpapers showing the calculation of the proposed RESRAM and shall include, at a minimum, the following information:

A. A complete explanation of all of the costs, both capital and expense, incurred for RES compliance that the electric utility is proposing be included in rates and the specific account used for each item;

B. The state, federal, and local income or excise tax rates used in calculating the proposed RESRAM, and an explanation of the source of and the basis for using those tax rates;

C. The regulatory capital structure used in calculating the proposed RESRAM, and an explanation of the source of and the basis for using the capital structure;

D. The cost rates for debt and preferred stock used in calculating the proposed RESRAM, and an explanation of the source of and the basis for using those rates;

E. The cost of common equity used in calculating the proposed RESRAM, and an explanation of the source of and the basis for that equity cost;

F. The depreciation rates used in calculating the proposed RESRAM, and an explanation of the source of and the basis for using those depreciation rates;

G. The rate base used in calculating the proposed RESRAM, including an updated depreciation reserve total incorporating the impact of all RES plant investments previously reflected in general rate proceedings or RESRAM application proceedings initiated following enactment of the RES rules;

H. The applicable customer class billing methodology used in calculating the proposed RESRAM, and an explanation of the source of and basis for using that methodology;

I. An explanation of how the proposed RESRAM is allocated among affected customer classes, if applicable; and

J. For purchase of electrical energy from eligible renewable energy resources bundled with the associated RECs or for the purchase of unbundled RECs, the cost of the purchases, and an explanation of the source of the energy or RECs and the basis for making that specific purchase, including an explanation of the request for proposal (RFP) process, or the reason(s) for not using a RFP process, used to establish which entity provided the energy or RECs associated with the RESRAM.

(C) RESRAM for equal to or greater than two percent (2%) actual increase in utility revenue requirements.

1. If an electric utility files an application and rate schedules to establish, continue, modify, or discontinue a RESRAM outside of a general rate proceeding, the staff shall examine and analyze the information filed in accordance with this section and additional information obtained through discovery, if any, to determine if the proposed RESRAM is in accordance with provisions of this rule and the statutes governing the RES. The commission shall establish a procedural schedule providing for an evidentiary hearing and commission report and order regarding the electric utility's filing. The staff shall submit a report regarding its examination and analysis to the commission not later than seventy-five (75) days after the electric utility files its application and rate schedules to establish a RESRAM. An individual or entity granted intervention by the commission may file comments not later than seventy-five (75) days after the electric utility files its application and rate schedules to establish a RESRAM. The electric utility shall have no less than fifteen (15) days from the filing of the staff's report and any intervener's comments to file a reply. The commission shall have no less than thirty (30) days from the filing of the electric utility's reply to hold a hearing and issue a report and order approving the electric utility's rate schedules subject to, or not subject to, conditions rejecting the electric utility's rate schedules, or rejecting the electric utility's rate schedules and authorizing the electric utility to file substitute rate schedules subject to, or not subject to, conditions.

2. When an electric utility files an application and rate schedules as described in this subsection, the electric utility shall file at the same time supporting direct testimony and the following supporting information as part of, or in addition to, its supporting direct testimony:

A. Proposed RESRAM rate schedules;

B. A general description of the design and intended operation of the proposed RESRAM;

C. A complete description of how the proposed RESRAM is compatible with the requirement for prudence reviews;

D. A complete explanation of all the costs that shall be considered for recovery under the proposed RESRAM and the specific account used for each cost item on the electric utility's books and records;

E. A complete explanation of all of the costs, both capital and expense, incurred for RES compliance that the electric utility is proposing be included in rates and the specific account used for each cost item on the electric utility's books and records;

F. A complete explanation of all of the costs, both capital and expense, incurred for RES compliance that the electric utility is proposing be included in base rates and the specific account used for each cost item on the electric utility's books and records;

G. A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RESRAM and the specific account where each such revenue item is recorded on the electric utility's books and records;

H. A complete explanation of any feature designed into the proposed RESRAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RESRAM;

I. For each of the major categories of costs, that the electric utility seeks to recover through its proposed RESRAM, a complete explanation of the specific rate class cost allocations and rate design used to calculate the proposed RES compliance revenue requirement and any subsequent RESRAM rate adjustments during the term of the proposed RESRAM; and

J. Any additional information that may have been ordered by the commission in a prior rate proceeding to be provided.

3. When an electric utility files rate schedules as described in this subsection, and serves upon parties as provided in paragraph (A)20. of this section, the rate schedules must be accompanied by supporting direct testimony, and at least the following supporting information:

A. The following information shall be included with the filing:

(I) For the period from which historical costs are used to adjust the RESRAM rate:

(a) REC costs differentiated by purchases, swaps, and loans;

(b) Net revenues from REC sales, swaps, and loans;

(c) Extraordinary costs not to be passed through, if any, due to such costs being an insured loss, or subject to reduction due to litigation, or for any other reason;

(d) Base rate component of RES compliance costs and revenues;

(e) Identification of capital projects placed in service that were not anticipated in the previous general rate proceeding; and

(f) Any additional requirements ordered by the commission in the prior rate proceeding;

(II) The levels of RES compliance capital costs and expenses in the base rate revenue requirement from the prior general rate proceeding;

(III) The levels of RES compliance capital cost in the base rate revenue requirement from the prior general rate proceeding as adjusted for the proposed date of the periodic adjustment;

(IV) The capital structure as determined in the prior rate proceeding;

(V) The cost rates for the electric utility's debt and preferred stock as determined in the prior rate proceeding;

(VI) The electric utility's cost of common equity as determined in the prior rate proceeding;

(VII) The rate base used in calculating the proposed RESRAM, including an updated depreciation reserve total incorporating the impact of all RES plant investments previously reflected in general rate proceedings or RESRAM application proceedings initiated following enactment of the RES rules; and

(VIII) Calculation of the proposed RESRAM collection rates; and

B. Workpapers supporting all items in subparagraph (C)3.A. of this section shall be submitted to the manager of the auditing department and served upon parties as provided in paragraph (A)20. in this section. The workpapers may be submitted to the manager of the auditing department through EFIS.

(D) Alternatively, an electric utility may recover RES compliance costs without use of the RESRAM procedure through rates established in a general rate proceeding. In the interim between general rate proceedings the electric utility may defer the costs in a regulatory asset account, and monthly calculate a carrying charge on the balance in that regulatory asset account equal to its short-term cost of borrowing. All questions pertaining to rate recovery of the RES compliance costs in a subsequent general rate proceeding will be reserved to that proceeding, including the prudence of the costs for which rate recovery is sought and the period of time over which any costs allowed rate recovery will be amortized. Any rate recovery granted to RES compliance costs under this alternative approach will be fully subject to the rate limit set forth in section (5) of this rule.

(7) Nothing in sections (5) and (6) of this rule shall relieve the electric utility from reviewing its initial or ongoing decisions related to adding renewable resource additions or affect the commission's ability to review the prudence of the electric utility's renewable resource additions.

(8) Annual RES Compliance Report and RES Compliance Plan. Each electric utility shall file a RES compliance report no later than April 15 to report on the status of both its compliance with the RES and its compliance plan as described in this section for the most recently completed calendar year. Each electric utility shall file an annual RES compliance plan with the commission. The plan shall be filed no later than April 15 of each year.

(A) Annual RES Compliance Report.

1. The annual RES compliance report shall provide the following information for the most recently completed calendar year for the electric utility:

A. Total retail electric sales for the utility, as defined by this rule;

B. Total jurisdictional revenue from the total retail electric sales to Missouri customers as measured at the customers' meters;

C. Total retail electric sales supplied by renewable energy resources, as defined by section 393.1025(5), RSMo, including the source of the energy;

D. The number of RECs and S-RECs created by electrical energy produced by renewable energy resources owned by the electric utility. For the electrical energy produced by these utility-owned renewable energy resources, the value of the energy created. For the RECs and S-RECs, a calculated REC or S-REC value for each source and each category of REC;

E. The number of RECs acquired, sold, transferred, or retired by the utility during the calendar year;

F. The source of all RECs acquired during the calendar year;

G. The identification, by source and serial number, or some other identifier sufficient to establish the vintage and source of the REC, of any RECs that have been carried forward to a future calendar year;

H. An explanation of how any gains or losses from sale or purchase of RECs for the calendar year have been accounted for in any rate adjustment mechanism that was in effect for the electric utility;

I. For acquisition of electrical energy and/or RECs from a renewable energy resource that is not owned by the electric utility, except for systems owned by customer-generators, the following information for each resource that has a rated capacity of ten (10) kW or greater:

(I) Facility name, location (city, state), and owner;

(II) That the energy was derived from an eligible renewable energy technology and that the renewable attributes of the energy have not been used to meet the requirements of any other local or state mandate;

(III) The renewable energy technology utilized at the facility;

(IV) The dates and amounts of all payments from the electric utility to the owner of the facility; and

(V) All meter readings used for calculation of the payments referenced in part (IV) of this paragraph;

J. For acquisition of electrical energy and/or RECs from a customer generator—

(I) Location (zip code);

(II) Name of aggregated subaccount in which RECs are being tracked in;

(III) Interconnection date;

(IV) Annual estimated or measured generation; and

(V) The start and end date of any estimated or measured RECs being acquired;

K. The total number of customers that applied and received a solar rebate in accordance with section (4) of this rule;

L. The total number of customers that were denied a solar rebate and the reason(s) for each denial;

M. The amount expended by the electric utility for solar rebates, including the price and terms of future S-REC contracts associated with the facilities that qualified for the solar rebates;

N. An affidavit documenting the electric utility's compliance with the RES compliance plan as described in this section during the calendar year;

O. If compliance was not achieved, an explanation why the electric utility failed to meet the RES; and

P. A calculation of its actual calendar year retail rate impact.

2. On the same date that the electric utility files its annual RES compliance report, the utility shall post an electronic copy of its annual RES compliance report, excluding highly confidential or proprietary material, on its website to facilitate public access and review.

3. On the same date that the electric utility files its annual RES compliance report, the utility shall provide the commission with separate electronic copies of its annual RES compliance report including and excluding highly confidential and proprietary material. The commission shall place the redacted electronic copies of each electric utility's annual RES compliance reports on the commission's website in order to facilitate public viewing, as appropriate.

(B) RES Compliance Plan.

1. The plan shall cover the current year and the immediately following two (2) calendar years. The RES compliance plan shall include, at a minimum—

A. A specific description of the electric utility's planned actions to comply with the RES;

B. A list of executed contracts to purchase RECs (whether or not bundled with energy), including type of renewable energy resource, expected amount of energy to be delivered, and contract duration and terms;

C. The projected total retail electric sales for each year;

D. Any differences, as a result of RES compliance, from the utility's preferred resource plan as described in the most recent electric utility resource plan filed with the commission in accordance with 4 CSR 240-22, Electric Utility Resource Planning;

E. A detailed analysis providing information necessary to verify that the RES compliance plan is the least cost, prudent methodology to achieve compliance with the RES;

F. A calculation of the RES retail impact limit calculated in accordance with section (5) of this rule. The calculation should be accompanied by workpapers including all the relevant inputs used to calculate the retail impact limits for the planning interval which is included in the RES compliance plan. The electric utility may designate all or part of those calculations as highly confidential, proprietary, or public as appropriate under the commission's rules; and

G. Verification that the utility has met the requirements for not causing undue adverse air, water, or land use impacts pursuant to subsection 393.1030.4., RSMo, and the regulations of the division.

(C) Upon receipt of the electric utility's annual RES compliance report and RES compliance plan, the commission shall establish a docket for the purpose of receiving the report and plan. The commission shall issue a general notice of the filing.

(D) The staff of the commission shall examine each electric utility's annual RES compliance report and RES compliance plan and file a report of its review with the commission within forty-five (45) days of the filing of the annual RES compliance report and RES compliance plan with the commission. The staff's report shall identify any deficiencies in the electric utility's compliance with the RES.

(E) OPC and any interested persons or entities may file comments based on their review of the electric utility's annual RES compliance report and RES compliance plan within forty-five (45) days of the electric utility's filing of its compliance report with the commission.

(F) The commission may direct the electric utility to provide additional information or to address any concerns or deficiencies identified in the comments of staff or other interested persons or entities.

(9) Penalties. An electric utility shall be subject to penalties of at least twice the average market value of RECs or S-RECs for the calendar year for failure to meet the targets of section 393.1030.1, RSMo, and section (2) of this rule.

(A) Any allegation of a failure to comply with the RES shall be filed as a complaint under the statutes and regulations governing complaints.

(B) An electric utility shall be excused if it proves to the commission that failure was due to events beyond its reasonable control that could not have been reasonably mitigated or to the extent that the maximum average retail rate impact increase, as determined in accordance with section (5) of this rule, would be exceeded.

(C) Any penalty payments assessed by the courts shall be remitted to the division. These payments shall be utilized by the division for the following purposes:

1. Purchase RECs or S-RECs in sufficient quantity to offset the shortfall of the utility to meet the RES portfolio requirements; and

2. Payments in excess of those required in paragraph (C)1. of this section shall be utilized to provide funding for renewable energy and energy efficiency projects. These projects shall be selected by the division in consultation with the staff.

(D) Upon determination by the commission that an electric utility has not complied with the RES, penalty amounts shall be calculated by determining the electric utility's shortfall relative to the RES portfolio requirements (total and solar) for the calendar year. The penalty amount recommended by the commission to the court of jurisdiction shall be twice the average market value during the calendar year for RECs or S-RECs in sufficient quantity to make up the utility's shortfall for RES total requirements or RES solar energy requirements. The average market value for RECs or S-RECs for the calendar year shall be based on RECs and S-RECs utilized for compliance with this rule. A recommended average market value for the compliance period shall be calculated by the staff. OPC and any interested persons or entities may file comments based on their review of the staff's recommendation. The commission may issue an order which establishes a further procedural schedule, or the commission may determine the average market value as part of the complaint proceeding.

(E) Any electric utility that is subject to penalties as prescribed by this section shall not seek recovery of the penalties through section (6) of this rule or any other rate-making activity.

(10) Nothing in this rule shall preclude a complaint case from being filed, as provided by law, on the grounds that an electric utility is earning more than a fair return on equity, nor shall an electric utility be permitted to use the existence of its RESRAM as a defense to a complaint case based upon an allegation that it is earning more than a fair return on equity.

(11) Variances. Upon written application, and after notice and an opportunity for hearing, the commission may grant a variance from any provision of this rule for good cause shown.

(A) The granting of a variance to one (1) electric utility which affects the required compliance with a provision of this rule does not constitute a variance respecting, or otherwise affect, the compliance required of any other electric utility.

(B) The commission may not grant a variance from this rule in total.

Electric Company
12 Months Ended ________________
Per Books
(IN THOUSANDS OF DOLLARS)
FINANCIAL SURVEILLANCE MONITORING REPORT
RATE BASE AND RATE OF RETURN

					12 Months Ended
Electric					
Total Electric Rate Base	**Measurement Basis**				
Plant in Service					
Intangible	End of Period	$	xxx,xxx		
Production - Steam	End of Period		xxx,xxx		
Production - Nuclear	End of Period		xxx,xxx		
Production - Hydraulic	End of Period		xxx,xxx		
Production - Other	End of Period		xxx,xxx		
Transmission	End of Period		xxx,xxx		
Distribution	End of Period		xxx,xxx		
General	End of Period		xxx,xxx		
Total Plant in Service				$	x,xxx,xxx
Reserve for Depreciation					
Intangible	End of Period		xxx,xxx		
Production - Steam	End of Period		xxx,xxx		
Production - Nuclear	End of Period		xxx,xxx		
Production - Hydraulic	End of Period		xxx,xxx		
Production - Other	End of Period		xxx,xxx		
Transmission	End of Period		xxx,xxx		
Distribution	End of Period		xxx,xxx		
General	End of Period		xxx,xxx		
Total Reserve for Depreciation					x,xxx,xxx
Net Plant				$	x,xxx,xxx
Add:					
Materials & Supplies	13 Mo. Avg.				x,xxx,xxx
Cash	{from prior rate case including offsets}				x,xxx,xxx
Fuel Inventory	13 Mo. Avg.				x,xxx,xxx
Prepayments	13 Mo. Avg.				x,xxx,xxx
Other Regulatory Assets	End of Period				x,xxx,xxx
Less:					
Customer Advances	13 Mo. Avg.				x,xxx,xxx
Customer Deposits	13 Mo. Avg.				x,xxx,xxx
Accumulated Deferred Income Taxes	End of Period				x,xxx,xxx
Other Regulatory Liabilities	End of Period				x,xxx,xxx
Other Items from Prior Rate Case	Per rate case method				x,xxx,xxx
(A) Total Rate Base				$	x,xxx,xxx
(B) Net Operating Income				$	x,xxx,xxx
(C) Return on Rate Base [(B) / (A)]					

Electric Company
12 Months Ended ________________
Per Books
(IN THOUSANDS OF DOLLARS)
FINANCIAL SURVEILLANCE MONITORING REPORT
CAPITAL STRUCTURE AND RATE OF RETURN

Overall Cost of Capital

		Amount	Percent	Cost		Weighted Cost
Long-Term Debt	$	xxx,xxx	x.xx %	x.xx %	f	x.xx %
Short-Term Debt		xxx,xxx	x.xx %	x.xx %	f	x.xx %
Preferred Stock		xxx,xxx	x.xx %	x.xx %	f	x.xx %
Other	d	xxx,xxx	x.xx %	x.xx %	f	x.xx %
Common Equity		xxx,xxx	x.xx %	x.xx %	a	x.xx %
Total Overall Cost of Capital based on Rate Case Rate of Return on Equity	$	x,xxx,xxx	100.00%			x.xx %

Actual Earned Return on Equity

		Amount	Percent	Cost		Weighted Cost	
Long-Term Debt	$	xxx,xxx	x.xx %	x.xx %	f	x.xx %	
Short-Term Debt (1)		xxx,xxx	x.xx %	x.xx %	f	x.xx %	
Preferred Stock		xxx,xxx	x.xx %	x.xx %	f	x.xx %	
Other	d	xxx,xxx	x.xx %	x.xx %	f	x.xx %	
Common Equity		xxx,xxx	x.xx %	x.xx %	a	x.xx %	
Total Overall Cost of Capital with Actual Return on Equity	$	x,xxx,xxx	100.00%			x.xx %	b

a From last general rate case, Report & Order.
b From actual Return on Rate Base, Page 1 "Rate Base"
c Calculated after actual Return on Rate Base, per footnote B, is determined.
d Other capital structure components from last general rate case, Report & Order
e Actual balance at end of period
f Actual average cost at end of period

Note Additional breakdown may be added per Report & Order authorizing a recovery clause under 4 CSR 240-20

Electric Company
Quarter Ended and 12 Months Ended ________________
Per Books
(IN THOUSANDS OF DOLLARS)
FINANCIAL SURVEILLANCE MONITORING REPORT
OPERATING INCOME STATEMENT

Total Electric Income Statement	QUARTER ENDED ACTUAL		12 MONTHS ENDED ACTUAL	
Operating Revenues				
Sales to Residential, Commercial, & Industrial Customers				
Residential	$ x,xxx,xxx		$ x,xxx,xxx	
Commercial	x,xxx,xxx		x,xxx,xxx	
Industrial	x,xxx,xxx		x,xxx,xxx	
Total of Sales to Residential, Commercial, & Industrial Customers		$ x,xxx,xxx		$ x,xxx,xxx
Other Sales to Ultimate Consumers		x,xxx,xxx		x,xxx,xxx
Sales for Resale		x,xxx,xxx		x,xxx,xxx
Off-System Sales		x,xxx,xxx		x,xxx,xxx
Other Operating Revenues		x,xxx,xxx		x,xxx,xxx
Provision for Refunds		x,xxx,xxx		x,xxx,xxx
Operating Revenues		$ x,xxx,xxx		$ x,xxx,xxx
Operating & Maintenance Expenses				
Production Expenses				
Fuel Expense				
Native Load	x,xxx,xxx		x,xxx,xxx	
Off-System Sales	x,xxx,xxx		x,xxx,xxx	
Other Production-Operations	x,xxx,xxx		x,xxx,xxx	
Other Production-Maintenance	x,xxx,xxx		x,xxx,xxx	
Purchased Power-Energy				
Native Load	x,xxx,xxx		x,xxx,xxx	
Off-System Sales	x,xxx,xxx		x,xxx,xxx	
Purchased Power-Capacity	x,xxx,xxx		x,xxx,xxx	
Total Production Expenses		x,xxx,xxx		x,xxx,xxx
Transmission Expenses		x,xxx,xxx		x,xxx,xxx
Distribution Expenses		x,xxx,xxx		x,xxx,xxx
Customer Accounts Expense		x,xxx,xxx		x,xxx,xxx
Customer Serve. & Info. Expenses		x,xxx,xxx		x,xxx,xxx
Sales Expenses		x,xxx,xxx		x,xxx,xxx
Administrative & General Expenses		x,xxx,xxx		x,xxx,xxx
Total Operating & Maintenance Expenses		$ x,xxx,xxx		$ x,xxx,xxx
Depreciation & Amortization Expense				
Depreciation Expense	x,xxx,xxx		x,xxx,xxx	
Amortization Expense	x,xxx,xxx		x,xxx,xxx	
Decommissioning expense	x,xxx,xxx		x,xxx,xxx	
Other	x,xxx,xxx		x,xxx,xxx	
Total Depreciation & Amortization Expense		x,xxx,xxx		x,xxx,xxx
Taxes Other than Income Taxes		xxx,xxx		xxx,xxx
Operating Income Before Income Taxes		$ x,xxx,xxx		$ x,xxx,xxx
Income Taxes		xxx,xxx		xxx,xxx
Net Operating Income		$ x,xxx,xxx		$ x,xxx,xxx
Actual Cooling Degree Days		x,xxx		x,xxx
Normal Cooling Degree Days		x,xxx		x,xxx
Actual Heating Degree Days		x,xxx		x,xxx
Normal Heating Degree Days		x,xxx		x,xxx

Electric Company
12 Months Ended ________________
FINANCIAL SURVEILLANCE MONITORING REPORT
Missouri Jurisdictional Allocation Factors

Description	Allocation Factor
Plant in Service	
Intangible	
Production - Steam	
Production - Nuclear	
Production - Hydraulic	
Production - Other	
Transmission	
Distribution	
General	
Reserve for Depreciation	
Intangible	
Production - Steam	
Production - Nuclear	
Production - Hydraulic	
Production - Other	
Transmission	
Distribution	
General	
Net Plant	
Materials & Supplies	
Cash Working Capital	per rate case
Fuel Inventory	
Prepayments	
Other Regulatory Assets	Jurisdictional Specific
Customer Advances	
Customer Deposits	
Accumulated Deferred Income Taxes	
Other Regulatory Liabilities	Jurisdictional Specific
Other Items from Prior Rate Case	
Operating Revenues	
Interchange Revenues	
Production Expenses	
Fuel Expense	
Native Load	
Off-System Sales	
Other Production-Operations	
Other Production-Maintenance	
Purchased Power-Energy	
Native Load	
Off-System Sales	
Purchased Power-Capacity	
Total Production Expenses	
Transmission Expenses	
Distribution Expenses	
Customer Accounts Expense	
Customer Serve. & Info. Expenses	
Sales Expenses	
Administrative & General Expenses	
Depreciation & Amortization Expense	
Depreciation Expense	
Amortization Expense	
Decommissioning expense	
Taxes Other than Income Taxes	
Income Taxes	
Other Items	
xxxx	
xxxx	
xxxx	

Note **Additional breakdown may be added per Report & Order authorizing a recovery clause under 4 CSR 240-20**

Electric Company
Quarter Ended and 12 Months Ended ________________
Per Books
FINANCIAL SURVEILLANCE MONITORING REPORT

NOTES TO FINANCIAL SURVEILLANCE REPORT

Illustration - Attachment A

RES Budget and Actual with Carryover

2013-2022 RRI Calculation Period

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year "Budget"
Baseline Rev. Req. (MM$)	$ 2,000.0	$ 2,100.0	$ 2,200.0	$ 2,300.0	$ 2,400.0	$ 2,500.0	$ 2,600.0	$ 2,700.0	$ 2,800.0	$ 2,900.0	
Annual 1% (MM$)	$ 20.0	$ 21.0	$ 22.0	$ 23.0	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 245.0
Actual Costs	$ 25.0	$ 35.0	$ 5.0	$ 5.0	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 245.0
Annual Over/(Under)	$ 5.0	$ 14.0	$ (17.0)	$ (18.0)	$ (19.0)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	
Cumulative CarryOver - Over/(Under)	$ 5.0	$ 19.0	$ 2.0	$ (16.0)	$ (35.0)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	

2014-2023 RRI Calculation Period

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10-Year "Budget"	Cumulative "Budget"
Baseline Rev. Req. (MM$)	$ 2,100.0	$ 2,200.0	$ 2,300.0	$ 2,400.0	$ 2,500.0	$ 2,600.0	$ 2,700.0	$ 2,800.0	$ 2,900.0	$ 3,000.0		
Annual 1% (MM$)	$ 21.0	$ 22.0	$ 23.0	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 255.0	$ 275.0
									Less Carryover		$ (5.0)	
									Adjusted "Budget"		$ 250.0	Cumulative Actual
Actual Costs	$ 35.0	$ 5.0	$ 5.0	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 250.0	$ 275.0
Annual Over/(Under)	$ 14.0	$ (17.0)	$ (18.0)	$ (19.0)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -		
Plus Prior Carryover	$ 5.0											
Cumulative CarryOver - Over/(Under)	$ 19.0	$ 2.0	$ (16.0)	$ (35.0)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -		

2015-2024 RRI Calculation Period

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-Year "Budget"	Cumulative "Budget"
Baseline Rev. Req. (MM$)	$ 2,200.0	$ 2,300.0	$ 2,400.0	$ 2,500.0	$ 2,600.0	$ 2,700.0	$ 2,800.0	$ 2,900.0	$ 3,000.0	$ 3,100.0		
Annual 1% (MM$)	$ 22.0	$ 23.0	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 265.0	$ 306.0
									Less Carryover		$ (19.0)	
									Adjusted "Budget"		$ 246.0	Cumulative Actual
Actual Costs	$ 5.0	$ 5.0	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 246.0	$ 306.0
Annual Over/(Under)	$ (17.0)	$ (18.0)	$ (19.0)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -		
Plus Prior Carryover	$ 19.0											
Cumulative CarryOver - Over/(Under)	$ 2.0	$ (16.0)	$ (35.0)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -	$ -		

Attachment A Page 1 of 4

Illustration - Attachment A

2016-2025 RRI Calculation Period

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		Cumulative
Baseline Rev. Req. (MM$)	$2,300.0	$2,400.0	$2,500.0	$2,600.0	$2,700.0	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 23.0	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 275.0	$ 338.0
									Less Carryover		$ (2.0)	
									Adjusted "Budget"		$ 273.0	Cumulative Actual
Actual Costs	$ 5.0	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 273.0	$ 338.0
Annual Over/(Under)	$ (18.0)	$ (19.0)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -	$ -		
Plus Prior Carryover	$ 2.0											
Cumulative CarryOver - Over/(Under)	$ (16.0)	$ (35.0)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -	$ -	$ -		

2017-2026 RRI Calculation Period

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		Cumulative
Baseline Rev. Req. (MM$)	$2,400.0	$2,500.0	$2,600.0	$2,700.0	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 285.0	$ 371.0
									Less Carryover		$ 16.0	
									Adjusted "Budget"		$ 301.0	Cumulative Actual
Actual Costs	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 301.0	$ 371.0
Annual Over/(Under)	$ (19.0)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -	$ -	$ -		
Plus Prior Carryover	$ (16.0)											
Cumulative CarryOver - Over/(Under)	$ (35.0)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -	$ -	$ -	$ -		

2018-2027 RRI Calculation Period

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		Cumulative
Baseline Rev. Req. (MM$)	$2,500.0	$2,600.0	$2,700.0	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	$3,400.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 295.0	$ 405.0
									Less Carryover		$ 35.0	
									Adjusted "Budget"		$ 330.0	Cumulative Actual
Actual Costs	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 330.0	$ 405.0
Annual Over/(Under)	$ 15.0	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -	$ -	$ -	$ -		
Plus Prior Carryover	$ (35.0)											
Cumulative CarryOver - Over/(Under)	$ (20.0)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -		

Attachment A Page 2 of 4

Illustration - Attachment A

2019-2028 RRI Calculation Period

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		Cumulative
Baseline Rev. Req. (MM$)	$2,600.0	$2,700.0	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	$3,400.0	$3,500.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 305.0	$ 440.0
									Less Carryover		$ 20.0	
									Adjusted "Budget"		$ 325.0	Cumulative Actual
Actual Costs	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 325.0	$ 440.0
Annual Over/(Under)	$ 11.0	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -	$ -	$ -	$ -	$ -		
Plus Prior Carryover	$ (20.0)											
Cumulative CarryOver - Over/(Under)	$ (9.0)	$ (2.0)	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -		

2020-2029 RRI Calculation Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		Cumulative
Baseline Rev. Req. (MM$)	$2,700.0	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	$3,400.0	$3,500.0	$3,600.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 27.0	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 315.0	$ 476.0
									Less Carryover		$ 9.0	
									Adjusted "Budget"		$ 324.0	Cumulative Actual
Actual Costs	$ 34.0	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 324.0	$ 476.0
Annual Over/(Under)	$ 7.0	$ 3.0	$ (1.0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Plus Prior Carryover	$ (9.0)											
Cumulative CarryOver - Over/(Under)	$ (2.0)	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		

2021-2030 RRI Calculation Period

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		Cumulative
Baseline Rev. Req. (MM$)	$2,800.0	$2,900.0	$3,000.0	$3,100.0	$3,200.0	$3,300.0	$3,400.0	$3,500.0	$3,600.0	$3,700.0	10-Year "Budget"	"Budget"
Annual 1% (MM$)	$ 28.0	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 37.0	$ 325.0	$ 513.0
									Less Carryover		$ 2.0	
									Adjusted "Budget"		$ 327.0	Cumulative Actual
Actual Costs	$ 31.0	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 37.0	$ 327.0	$ 513.0
Annual Over/(Under)	$ 3.0	$ (1.0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		

Attachment A Page 3 of 4

Illustration - Attachment A

Plus Prior Carryover	$ (2.0)									
Cumulative CarryOver - Over/(Under)	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2022-2031 RRI Calculation Period

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031			Cumulative "Budget"
Baseline Rev. Req. (MM$)	$ 2,900.0	$ 3,000.0	$ 3,100.0	$ 3,200.0	$ 3,300.0	$ 3,400.0	$ 3,500.0	$ 3,600.0	$ 3,700.0	$ 3,800.0	10-Year "Budget"		
Annual 1% (MM$)	$ 29.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 37.0	$ 38.0	$ 335.0		$ 551.0
									Less Carryover		$ (1.0)		
									Adjusted "Budget"		$ 334.0		Cumulative Actual
Actual Costs	$ 28.0	$ 30.0	$ 31.0	$ 32.0	$ 33.0	$ 34.0	$ 35.0	$ 36.0	$ 37.0	$ 38.0	$ 334.0		$ 551.0
Annual Over/(Under)	$ (1.0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Plus Prior Carryover	$ 1.0												
Cumulative CarryOver - Over/(Under)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	TOTAL
Actual Spend 2013-2022	$ 25.0	$ 35.0	$ 5.0	$ 5.0	$ 5.0	$ 40.0	$ 37.0	$ 34.0	$ 31.0	$ 28.0	$ 245.0
Budget 2013-2022	$ 20.0	$ 21.0	$ 22.0	$ 23.0	$ 24.0	$ 25.0	$ 26.0	$ 27.0	$ 28.0	$ 29.0	$ 245.0
Revenue Requirement 2013-2022	$ 2,000.0	$ 2,100.0	$ 2,200.0	$ 2,300.0	$ 2,400.0	$ 2,500.0	$ 2,600.0	$ 2,700.0	$ 2,800.0	$ 2,900.0	$ 24,500.0
Budget % of Revenue Requirement	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Actual % of Revenue Requirement	1.3%	1.7%	0.2%	0.2%	0.2%	1.6%	1.4%	1.3%	1.1%	1.0%	1.0%

Attachment A Page 4 of 4

AUTHORITY: section 393.1030, RSMo Supp. 2018, and sections 386.040 and 386.250, RSMo 2016. This rule originally filed as 4 CSR 240-20.100. Original rule filed Jan. 8, 2010, effective Sept. 30, 2010. Amended: Filed March 25, 2015, effective Nov. 30, 2015. Amended: Filed Feb. 27, 2019, effective Oct. 30, 2019. Moved to 20 CSR 4240-20.100, effective Aug. 28, 2019.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; and 393.1030, RSMo 2007, amended 2008, 2010, 2013, 2018.*

*****Ruling by the Joint Committee on Administrative Rules****. On July 1, 2010, the Joint Committee on Administrative Rules voted to disapprove subsection (2)(A) and paragraph (2)(B)2. of 4 CSR 240-20.100. Those portions contained provisions on geographic sourcing. The committee considered those portions which were disapproved to be held in abeyance and asked that they not be published.*

Public Service Commission action. *On January 26, 2011, the Public Service Commission filed an order with the Administrative Rules Division of the Office of the Secretary of State withdrawing the geographic sourcing provisions found in subsection (2)(A) and paragraph (2)(B)2. of 4 CSR 240-20.100. This commission order renewed the request of the Public Service Commission submitted by letter with its final order of rulemaking on July 6, 2010, that subsection (2)(A) and paragraph (2)(B)2. not be published in the* ***Code of State Regulations*** *and that these portions of the rule not become effective. A copy of this order appeared in the April 1, 2011, issue of the* ***Missouri Register*** *(36 MoReg 1002–1007).*

Legislative action. *On January 24, 2011, Senate Concurrent Resolution No. 1 regarding 4 CSR 240-20.100 was adopted by the Senate and was concurred in by the House of Representatives on February 1, 2011. On February 16, 2011, the governor sent a letter to the speaker of the Missouri House of Representatives and the president pro tem of the Missouri Senate serving as notice of his action on the resolution. This concurrent resolution upheld a ruling issued by the Joint Committee on Administrative Rules disapproving subsection (2)(A) and paragraph (2)(B)2. of 4 CSR 240-20.100. The concurrent resolution permanently disapproves and suspends the final order of rulemaking for the proposed amendment to the above stated subsection and paragraph. The concurrent resolution and the letter from the governor were published in the April 1, 2011, issue of the* ***Missouri Register*** *(36 MoReg 1008–1011).*

20 CSR 4240-20.105 Filing Requirements for Electric Utility Rate Schedules

PURPOSE: This rule updates language and streamlines provisions formerly in Chapter 3.

(1) Every electrical corporation, as defined in section 386.020, RSMo, engaged in the manufacture, generation, furnishing, or transmission of electricity for light, heat, or power within Missouri is directed to have on file with this commission a schedule of all rates, rentals, and charges of whatever nature made by the electrical corporation for each kind of service it renders which are in force, together with proper supplements covering all changes in rate schedules authorized by this commission, if any.

(2) Every electrical corporation is directed to keep a paper copy of its rate schedules approved by this commission in its main or principal Missouri operating office and to make those rate schedules readily accessible to the public upon demand during regularly scheduled business hours of that office. Every electrical corporation shall also publish a currently effective rate schedule on its website and make the electronic schedule readily available to the public. The electrical corporation shall provide access in person or by telephone during regular business hours to customer service representatives who can aide customers in determining accurately the rate or charge applicable to any particular kind of electrical service.

(3) All schedules of rates, rentals, and charges, or rules relating and applying to service rendered in connection with the supplying of electrical energy for light, heat, and power or for any service rendered in connection with electrical energy supply, lawfully on file with the commission will be considered as continuing in force and may be amended in the manner provided in this rule.

(4) All schedules of rates must conform to this rule or they will be subject to rejection by the commission when tendered for filing. The commission reserves the right to direct the reprinting of any schedule at any time.

(5) In classifying rates for electrical service the following uniform system of classification will be followed as closely as practical:

(A) All lighting rates for residences, business places, theaters, public buildings, and the like will be placed under the head of commercial lighting;

(B) All power rates, including rates for battery charging, will be placed under the head of commercial power; and

(C) All rates for street lighting, including municipal street lighting and the free lighting of public buildings as is done in connection with street lighting will be placed under the head of street lighting.

(6) All schedules of rates filed with the commission shall bear a number with the following prefix: PSC Mo. Rate schedules shall be numbered in consecutive serial order commencing with a No. 1 for each electrical corporation (for example, the first schedule PSC Mo., No. 1). The prefixes and numbers shall be printed on schedules as required by section (9) of this rule. For convenience the prefix is referred to as PSC.

(7) All sheets except the title page must show in the marginal space at the top of page or sheet, the name of the electrical corporation issuing the PSC No., the number of the schedule and the number of the page or sheet. At the bottom of the sheet in the marginal space must be shown, the date of issue and effective date, and the name, title, and address of the officer by whom the schedule is issued.

(8) The title page or sheet of every schedule of rates shall show—

(A) The full corporate name of the issuing electrical corporation;

(B) The PSC number of the schedule in bold type in the center of the marginal space at top of the page and immediately under it in small type the PSC number(s) canceled;

(C) A brief description of the service areas from and to or within which the schedule applies;

(D) When a schedule rate is governed by a general publication, the reference to the general publication by its PSC number must be given. The following phraseology, as the case may be, will be used: "Governed except as otherwise provided herein by schedule PSC Mo. No., which schedule, revised and added pages or sheets or superseding issues thereof is hereby made a part of this schedule." The rate publication referred to must be on file with the commission and be kept at every place where the schedule making reference is to be kept for public inspection;

(E) The date of issue and the date effective. If the schedule or any portion is made to expire on a specified date, the following clause must be used: "expires, unless sooner changed, canceled, or extended";

(F) On every schedule, supplement, or

revised or added sheet issued on less than thirty (30) days' notice, by permission of the commission, the following notation must be shown: "Issued on ____ days' notice to the public and the commission under special permission of the Public Service Commission of Missouri, No. ____ of date ____." If issued in compliance with an order of the commission, the following notation must be shown: "Issued on ____ days' notice to the public and the commission under order of the Public Service Commission of Missouri, of date ____, in Case No. ____," when issued by authority of any section of this rule, the notice must be that required by the particular section granting permission;

(G) On the upper left-hand corner of a schedule of fewer than three (3) pages the words, "No supplement to this tariff will be issued except for the purpose of canceling this tariff." A schedule of three (3) or more pages shall include the words, "Only one (1) supplement to this schedule will be in effect at any one (1) time"; and

(H) On the marginal space at the bottom of page will be given the name, title, and address of the officer by whom the schedule is issued, the date of issue, and the effective date.

(9) The schedule shall contain in the order named—

(A) Table of Contents. Provide full and complete statement in alphabetical order of the exact location where information under the general headings or subjects will be found, specifying the page of item numbers. If the schedule contains so small a volume of matter that its title page or interior arrangement plainly may disclose its contents, the table of contents may be omitted;

(B) Description of Territory. A more lengthy description of the territory to be served than can be briefly set forth on the title page will often be necessary; any items in this category which bear any relation to the various rates should be explained under this heading;

(C) Classification of Service. Under this heading the kind of service separately grouped for Residential and Non-Residential will be set forth in the order named together with a detailed statement of the rate(s) in connection with same. A definite separation must be made between prompt payment discount and quantity discount and stating the manner in which they are computed clearly. If guarantees of any nature are required or a minimum charge made, the principles upon which they are based must be stated. In this case give the company's charges or deposits for meters. If penalties for delayed payments are exacted, the same must be stated. State whether current is estimated or metered and, if so, how. State the company's practice in regard to lamp renewals. If a charge is made to the consumer for installing and connecting the service wires, this should be stated. State the character of the service, whether twenty-four- (24-) hour or limited until midnight, whether the service is limited to certain hours of the day, on-peak, off-peak, optional service, auxiliary service, breakdown service, and the like. The kind of current, such as alternating or direct, together with the voltage, phase, and frequency must be given in all cases;

(D) Rules. Under this heading will be set forth all rules which apply to contracts for furnishing electrical energy for light, heat, and power, and all of the company's rules in any way relating to service, together with any particular regulations relating to a special contract for service rendered which have not already been stated in connection with the description of rates under section (5) of this rule; and

(E) Definition and Explanation of Reference Marks. Under this heading, as its name implies, shall be given the necessary description of any reference marks employed in connection with the rate tables, that is, explain the meaning of watt, kilowatt hour, horsepower, and the like. If symbols or abbreviations are used, explain their meanings, such as kilowatt hour for K.W.H.; ampere for amp. When ratings are used based on capacity installation or a percentage of capacity installation, a table of equivalents for estimating these ratings must be given. For example, one (1) sixteen- (16-) candle power carbon filament lamp equals about fifty-five (55) watts. If terms maximum demand, load factor, rated capacity, peak, and the like, are used in the schedule, these should be explained under this caption. All definitions of terms and explanation of terms or symbols, abbreviations, or reference marks should be arranged in logical sequence and in a manner that they will be readily understood.

(10) If a schedule or supplement to a schedule is issued which conflicts with a part of another schedule or supplement of a schedule which is in force at the time and which is not canceled in full, it specifically shall state the portion of the other schedule which is canceled and the other schedule, at the same time, shall be correspondingly amended, effective on the same date, in the regular way; and the supplement to the amended schedule shall be filed at the same time and in connection with the schedule which contains the new rates, rentals, or charges.

(11) If a schedule is canceled with the purpose of canceling entirely the rates, rentals, or charges named in the schedule or when through error or omission, a later issue failed to cancel the previous issue and a schedule is canceled for the purpose of perfecting the record, the cancellation notice must not be given a new PSC number, but must be issued as a supplement to the schedule which it cancels, even though the schedule at the time may have a supplement in effect.

(12) If a schedule or a part of a schedule is canceled, the cancellation notice shall make specific notice to the PSC number of the schedule in which the rates, rentals, or charges will be found; or if no rates, rentals, or charges are in effect, it shall state so. Cancellation of a schedule also cancels a supplement to the schedule in effect, if any. If a schedule is canceled by a similar schedule to take its place, the cancellation notice must not be given by supplement, but by notice printed in a new schedule.

(13) A change in a schedule shall be known as an amendment and shall be published in a supplement to the schedule which it amends, specifying the schedule by its PSC number. The supplement shall be republished each time an amendment is made and shall always contain all the amendments to the schedule that are in force. Supplements to schedules shall be numbered consecutively as supplements to the schedules and shall not be given new or separate PSC numbers. An amendment must always be published in the supplement in its entirety as amended.

(14) A schedule which contains reissued items brought forward from a previous issue which has not been in effect thirty (30) days or a supplement which brings forward reissued items without change from a former supplement or schedule, must bear the notation "Effective _______________ , except as noted in individual items." "Example: Issued _____________________, 20___; effective _____________, 20___ , except as noted in individual items." Reissued items brought forward without change must show in a conspicuous form and convenient manner the following: "Reissue" in black face type; the effective or the date upon which it becomes effective; in PSC Mo. No. ________ "or in supplement No. ________ to PSC Mo. No. __________." When the reissued item became effective in a former supplement to the same schedule, the PSC number may be omitted, but the supplement number must be given.

(15) Except as otherwise provided in this rule, there shall be at no time more than one (1) supplement in effect to any schedule, and the effective supplement to a schedule of twenty (20) or more pages may not contain more than twenty percent (20%) of the number of pages or sheets in the schedule, including the title page. A supplement to a schedule of fewer than twenty (20) pages or ten (10) sheets may not contain more than four (4) pages or two (2) sheets, including the title page.

(16) All changes in and additions to schedules issued in paper must be made by reprinting the sheet upon which the change is made. Those pages or sheets shall not be given supplement numbers, but must be designated "First revised page or sheet," "Second revised page or sheet," and the like and must show the name of the issuing corporation and the PSC number of the schedule, the issued and effective dates, and the name, title, and address of the officer by whom issued.

(17) If a new schedule is filed on statutory notice canceling another schedule and after that filing and prior to the effective date of the new schedule, a supplement to the schedule to be so canceled should be lawfully issued, the rates, rentals, or charges in that supplement could not continue in effect for the thirty (30) days required by law because the cancellation of the schedule also cancels the supplement to it. In this case the supplement containing changes not included in the schedule that is to become effective may be issued as a supplement both to the schedule in effect and to the schedule on file that will effect a cancellation and be given both PSC numbers. In other words, such an issue must be a supplement of each of the schedules and copies must be filed accordingly. A supplement issued under this rule containing reissued items shall note in connection with each item, in addition to the effective date required by this rule, that the reissued items expire on the date on which the new schedule will apply in lieu thereof; and the reissued items must not be brought forward in a subsequent supplement to the new schedule. This supplement may not contain any changes except those lawfully made by supplement to the schedule which is to be canceled by the schedule that has been filed and that is also supplemented; and no other kind of a supplement to a schedule that is on file and not yet effective may be made effective within thirty (30) days from the effective date of the schedule without special permission of the commission.

(18) The provisions of section (15) of this rule as to the number of supplements to a schedule that may be in effect at any time and the volume of supplemental matter they may contain need not be observed in connection with a supplement issued under sections (14)–(18) of this rule.

(19) In case of change of ownership and operation of any electrical corporation's property or of the electrical corporation in possession and operating the property, the electrical corporation taking over the operation of the properties, if the existing rates would otherwise remain legally effective, shall issue immediately and file with the commission, with PSC number, an adoption notice substantially as follows:

(A) "The (name of the electrical corporation) hereby adopts, ratifies, and makes its own, in every respect as if the same had been originally filed by it, all schedules, rules, notices, concurrences, schedule agreements, divisions, authorities, or other instruments whatsoever, filed with the PUBLIC SERVICE COMMISSION, State of Missouri, by the (name of the electrical corporation), prior to (date), the beginning of its possession. By this notice it also adopts and ratifies all supplements or amendments to any of the above schedules, etc., which (name of the electrical corporation) has heretofore filed with said commission. This notice may be made effective as of the date it is filed with the commission.";

(B) In the event that the successor corporation does not intend to adopt some of those schedules, rates, rules, notices, concurrences, authorities, or other instruments, the notice shall specify those which are not adopted, and the successor corporation as to such exceptions shall give the cancellation or withdrawal notice provided in this rule;

(C) The adoption notice shall stand and be effective as to all of the local issues of the predecessor electrical corporation; and

(D) In case of a receivership, the receiver shall be deemed as continuing in force the schedules and rules of the corporation whose property s/he has in charge.

(20) Schedules and schedule supplements shall be filed with the commission by the proper officer of the electrical corporation designated to perform that duty; and supplements must be on file with the commission or accompany the schedule or supplement.

(21) All changes in rates, charges, or rentals or in rules that affect the rates, charges, or rentals shall be filed with the commission at least thirty (30) days before the date upon which they are to become effective. The title page of every rate schedule or supplement and the reissue on any page or sheet must show a full thirty (30) days' notice except as otherwise provided in this rule. The proposed change shall be accompanied by a brief summary, approximately one hundred (100) words or fewer, of the effect of the change on the company's customers. A copy of any proposed change and summary shall also be served on the public counsel and be available for public inspection and reproduction during regular office hours at the general business office of the utility.

(22) Each electrical corporation has the duty of filing with the commission all its schedules of rates and supplements or any rule relative to them which may be announced by the commission, under penalty for failure to do so. The commission will give consistent assistance as it can in this respect, but the fact that the receipt of a rate schedule or a supplement to a rate schedule is acknowledged by the commission, or the fact that a rate schedule or supplement to a rate schedule is in the files of the commission, will not serve or operate to excuse the electrical corporation from its responsibility or liability for any violation of the law or of any ruling lawfully made which may have occurred in connection thereunder with the construction of filing of a rate schedule or supplement.

(23) Thirty (30) days' notice to the commission is required as to every publication relating to electrical rates or service except where publications are made effective on less than statutory notice by permission, regulation, or requirement of the commission.

(24) Except as is otherwise provided, no schedule or supplement will be accepted for filing unless it is delivered to the commission free from all charges or claims for postage, the full thirty (30) days required by law before the date upon which the schedule or supplement is stated to be effective. No consideration will be given to or for the time during which a schedule or supplement may be held by the post office authorities because of insufficient postage. When a schedule or a supplement is issued and as to which the commission is not given the statutory notice, it is as if it had not been issued and a full statutory notice must be given of any reissue. In these cases the schedule will be returned to the sender and correction of the neglect or omission cannot be made which takes into account any time elapsing between the date upon which that schedule or supplement was received and the date of the attempted correction. For rate schedules and supplements

issued on short notice under special permission of the commission, literal compliance with the requirements for notice named in any order, regulation, or permission granted by the commission will be exacted.

(25) When a schedule is rejected by the commission as unlawful, the records will so show and that schedule should not in the future be referred to as canceled, amended, or otherwise except to note on the publication issued in lieu of that rejected schedule, "In lieu of ___________, rejected by the commission;" nor shall the number which it bears be used again.

(26) Rates, charges, or rentals or regulations relating to them, prescribed by the commission in its decisions and orders, after hearings upon formal complaints, shall in every instance be promulgated by the electrical corporation against which those orders are entered, in duly published and filed rate schedules, supplements, or revised pages or sheets of schedules, and notice shall be sent to the commission that its order in Case No. ___________ has been complied with in item ________, page ______, of schedule PSC Mo. No. _________; or supplement to schedule PSC Mo. No. __________; or reissued page or sheet No. _________ to schedule PSC Mo. No. _____________.

(27) Schedules and supplements shall be filed in numerical order of PSC numbers. If in any instance this procedure is not observed as required by these rules, a memorandum must accompany the schedule so filed with the commission explaining omission of missing number(s).

(28) Electrical corporations shall file any rate schedule, supplement, or other charges or regulations with the commission via the Electronic Filing and Information System (EFIS), or if filing a paper copy, to transmit or hand-deliver one (1) copy of each rate schedule, supplement, or other charges or regulations for the use of the commission. Schedules sent for filing must be addressed to Public Service Commission, PO Box 360, Jefferson City, MO 65102.

(29) All schedules filed with the commission shall be accompanied by a letter of transmittal which shall be prepared consistent with the format designated by the commission. If filing a paper copy and a paper receipt is desired, a duplicate copy should be submitted for return.

AUTHORITY: sections 386.250 and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-20.105. Original rule filed Nov. 7, 2018, effective July 30, 2019. Moved to 20 CSR 4240-20.105, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*