DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

RULES REGULATING ELECTRIC UTILITIES

4 CCR 723-3

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

BASIS, PURPOSE, AND STATUTORY AUTHORITY.

The basis and purpose of these rules is to describe the electric service to be provided by jurisdictional utilities and master meter operators to their customers; to designate the manner of regulation over such utilities and master meter operators; and to describe the services these utilities and master meter operators shall provide. In addition, these rules identify the specific provisions applicable to public utilities or other persons over which the Commission has limited jurisdiction. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, electric service low-income program, cost allocation between regulated and unregulated operations, recovery of costs, the acquisition of renewable energy, small power producers and cogeneration facilities, and appeals regarding local government land use decisions. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-2-124(2), 40-2-202, 40-2-203, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-113.5, 40-7-116.5, 40-8.7-105(5), and 40-9.5-107(5), C.R.S.

GENERAL PROVISIONS

3000. Scope and Applicability.

(a) Absent a specific statute, rule, or Commission Order which provides otherwise, all rules in this Part 3 (the 3000 series) shall apply to all jurisdictional electric utilities and electric master meter operators and to Commission proceedings concerning electric utilities or electric master meter operators providing electric service.

(b) The following rules in this Part 3 shall apply to cooperative electric associations which have elected to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-103, C.R.S.

(I) Paragraphs 3002 (a)(I), (a)(II), (a)(IV), (a)(V), (a)(XVI), (b), and (c) concerning the filing of applications for certificate of public convenience and necessity for franchise or service territory, for certificate amendments, to merge or transfer, or for appeals of local government actions.

(II) Paragraphs 3005 (a)(III), (IV), (d), (e), (g), and (h) concerning records under RUS accounting system and preservation of records.

(III) Paragraphs 3006 (a), (b), (c), (d), and (e) concerning the filing of annual reports, designation for service of process, and election of applicability of Title 40, Article 8.5.

(IV) Paragraphs 3008 (b) and (d) concerning incorporation by reference.

(V) Rules 3100 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to a franchise.

(VI) Rules 3101 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to service territory.

(VII) Rule 3104 concerning application to transfer assets, to obtain a controlling interest, or to merge with another entity.

(VIII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.

(IX) Paragraphs 3207 (a) and (b) concerning construction and expansion of distribution facilities.

(X) Rules 3250 through 3253 concerning major event reporting.

(XI) Rule 3411 concerning the Low-Income Energy Assistance Act unless the cooperative electric association has exempted themselves pursuant to paragraph 3411(a).

(XII) Rules 3650(b), 3651, 3652, 3654(b), (d) through (i), and (l); 3655(h)-(m); 3659(a)(I) through (a)(V), (b) and (d) through (i), 3660(l), 3661(b), (c), (g), and (i), 3662(a)(I), (a)(II), (a)(IV) through (a)(X), (a)(XIII), (a)(XV), (b), (d) and (e), and 3667.

(XIII) Rules 3700 through 3707 concerning appeals of local governmental land use decisions actions.

(c) The following rules in this Part 3 shall apply to cooperative electric generation and transmission associations.

(I) Paragraphs 3002 (a)(III), (a)(XVI), (b), and (c) concerning the filing of applications for certificates of public convenience and necessity for facilities or for appeals of local government actions.

(II) Paragraph 3006(j) concerning the filing of electric resource planning reports.

(III) Rule 3102 concerning applications for certificates of public convenience and necessity for facilities.

(IV) Rule 3103 concerning amendments to certificates of public convenience and necessity for facilities.

(V) Rule 3104 concerning application to transfer, to obtain a controlling interest, or to merger with another entity.

(VI) Rule 3200 concerning construction, installation, maintenance, and operation of facilities.

(VII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.

(VIII) Rule 3205 concerning construction or expansion of generating capacity.

(IX) Rule 3206 concerning construction or extension of transmission facilities.

(X) Paragraph 3253(a) concerning major event reporting.

(XI) Rules 3602, 3605, and 3618(a) concerning electric resource planning.

(XII) Rules 3650(e), 3651, 3652, 3662(f), and 3668(d) concerning the RES.

(XIII) Rules 3700 through 3707 concerning appeals of local government actions.

(d) The following rules in this Part 3 shall apply to municipally owned utilities, which are qualifying retail utilities:

(I) Rules 3650(c), 3651, 3652, 3653, 3654(b), (c), (d) through (i) and (l); 3659(a)(I) through (a)(V), (b), (d) through (i), 3666, and 3668(d).

(e) The following rules in this Part 3 shall apply to municipally owned utilities which are not qualifying retail utilities.

(I) Paragraph 3650(d).

3001. Definitions.

The following definitions apply throughout this Part 3, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

(a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a public utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.

(b) "Aggregated data" means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or the compilation of customer data of one or more customers from which all unique identifiers and personal information has been removed.

(c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.

(d) "Basis point" means one-hundredth of a percentage point (100 basis points = one percent).

(e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.

(f) "Commission" means the Colorado Public Utilities Commission.

(g) "Contracted agent" means any person that has contracted with a utility in compliance with rule 3030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).

(h) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility's service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.

(i) "Customer data" means customer-specific data or information, excluding personal information as defined in paragraph 1004(x), that is:

(I) collected from the electric meter by the utility and stored in its data systems (e.g., kWh, kW, voltage, VARs and power factor);

(II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or

(III) about the customer’s participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.

(j) “Distribution facilities” are those lines designed to operate at the utility's distribution voltages in the area as defined in the utility’s tariffs including substation transformers that transform electricity to a distribution voltage and also includes other equipment within a transforming substation which is not integral to the circuitry of the utility’s transmission system.

(k) “Energy assistance organization” means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(l) “Energy storage system” means a commercially available technology that is capable of retaining energy, storing the energy for a period of time, and delivering the energy as electricity after storage by chemical, thermal, mechanical, or other means.

(m) “Financial security” includes any stock, bond, note, or other evidence of indebtedness.

(n) “Generation facility” means a power plant that converts a primary energy resource into electricity. Primary energy resources include, but are not limited to: nuclear resources, coal, natural gas, hydro, wind, solar, biomass, and geothermal.

(o) “Heavy load” means not less than 60 percent, but not more than 100 percent, of the nameplate-rated capacity of a meter.

(p) “Informal complaint” means an informal complaint as defined and discussed in the Commission’s Rules Regulating Practice and Procedure.

(q) “Light load” means approximately five to ten percent of the nameplate-rated capacity of a meter.

(r) “Load” means the power consumed by an electric utility customer over time (measured in terms of either demand or energy or both).

(s) “Local government” means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.

(t) “Local office” means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, “local office” means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.

(u) “Main service terminal” means the point at which the utility’s metering connections terminate.

(v) “Major event” means an event as defined in and consistent with IEEE Standard Number 1366-2003, Guide for Electric Power Distribution Reliability Indices.

(w) “MVA” means mega-volt amperes and is the vector sum of the real power and the reactive power.

(x) “Non-standard customer data” means all customer data that are not standard customer data.

(y) "Output" means the energy and power produced by a generation system.

(z) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.

(aa) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.

(bb) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of property is located to determine ownership of government record.

(cc) "Reference standard" means suitable indicating electrical equipment permanently mounted in a utility's laboratory and used for no purpose other than testing rotating standards.

(dd) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission or contained in a tariff of the utility.

(ee) "RFP" means request for proposals.

(ff) "Rotating standard" means a portable meter used for testing service meters.

(gg) "RUS" means the Rural Utilities Service of the United States Department of Agriculture, or its successor agencies.

(hh) "Service connection" is the location on the customer's premises/facilities at which a point of delivery of power between the utility and the customer is established. For example, in the case of a typical residential customer served from overhead secondary supply, this is the location at which the utility's electric service drop conductors are physically connected to the customer's electric service entrance conductors.

(ii) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.

(jj) "Third-party" means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting of the customer's behalf, a regulated utility serving the customer, or a contracted agent, of the utility.

(kk) "Transmission facilities" are those lines and related substations designed and operating at voltage levels above the utility's voltages for distribution facilities, including but not limited to related substation facilities such as transformers, capacitor banks, or breakers that are integral to the circuitry of the utility's transmission system.

(ll) "Unique identifier" means a customer's name, mailing address, telephone number, or email address that is displayed on a bill.

(mm) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff filed with the Commission, and are for service or merchandise not required as a condition of receiving regulated utility service.

(nn) "Utility" means any public utility as defined in § 40-1-103, C.R.S., providing electric, steam, or associated services in the state of Colorado.

(oo) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(pp) "Whole building data" means the sum of the monthly electric use for either all meters at a building on a parcel or real property or all buildings on a parcel of real property.

3002. Applications.

(a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):

(I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 3100;

(II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 3101;

(III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 3102;

(IV) amendment of a certificate of public convenience and necessity in order to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 3103;

(V) transfer of a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 3104;

(VI) issuance, or assumption of any financial security or to create a lien pursuant to § 40-1-104, as provided in rule 3105;

(VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 3106;

(VIII) approval of an air quality improvement program, as provided for in rule 3107;

(IX) amendment of a tariff on less than statutory notice, as provided in rule 3109;

(X) variance of voltage standards, as provided in rule 3202;

(XI) approval of meter and equipment testing practices, as provided in rule 3303;

(XII) approval of a meter sampling program, as provided in rule 3304;

(XIII) approval of a refund plan, as provided in rule 3410;

(XIV) approval of a Low-Income Energy Assistance Plan, as provided in rule 3411;

(XV) approval of a cost assignment and allocation manual, as provided in rule 3503;

(XVI) approval of or for amendment to a least-cost resource plan, as provided in rules 3603, 3618, and 3619;

(XVII) approval of a compliance plan, as provided in rule 3657;

(XVIII) appeal of local government land use decision, as provided in rule 3703; or

(XIX) matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.

(b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the name and address of the applying utility;

(II) the name(s) under which the applying utility is, or will be, providing service in Colorado;

(III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;

(IV) a statement that the applying utility agrees to answer all questions propounded by the Commission staff concerning the application;

(V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;

(VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;

(VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule;

(VIII) a statement describing the applying utility’s existing operations and general service area in Colorado;

(IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, a copy of the applying utility's or parent company’s and consolidated subsidiaries’ most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;

(X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearings be held; and

(XI) acknowledgment that, by signing the application, the applying utility understands that:

(A) the filing of the application does not by itself constitute approval of the application;

(B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and any conditions established by Commission order granting the application;

(C) if a hearing is held, the applying utility must present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action; and

(D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.

(XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.

(c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the miscellaneous proceeding created under rule 1310.

(d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following.

(I) The title “Notice of Application by [Name of the Utility] to [Purpose of Application]”.

(II) State that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers.

(III) Provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice.

(IV) Identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application.

(V) Identify the proposed effective date of the application.

(VI) Identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable.

(VII) State that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission.

(VIII) Identify the proceeding number, if known at the time the customer notice is provided.

(IX) State that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application.

(X) State that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission's Rules of Practice and Procedure or any applicable Commission order.

(XI) State that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice.

(XII) State that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

3003. [Reserved].

3004. Disputes and Informal Complaints.

(a) For purposes of this rule, "dispute" means a concern, difficulty, or problem which needs resolution and which a customer or a person applying for service brings directly to the attention of the utility without the involvement of Commission staff or the Commission.

(b) A dispute may be initiated orally or in writing. Using the procedures found in rule 1301, a utility shall conduct a full and prompt investigation of all disputes concerning utility service.

(c) In accordance with the procedures in rule 1301, each utility shall conduct a full and prompt investigation of all informal complaints concerning utility service.

(d) A utility shall comply with all rules regarding the timelines for responding to informal complaints.

(e) If a current customer, or an applicant for service that is not a current customer, is dissatisfied with the utility's proposed adjustment or disposition of a dispute, the utility shall inform the person, customer or applicant for service of the right to make an informal complaint to the External Affairs section of the Commission and shall provide to the person, customer or applicant for service the address and toll free number of the Commission's External Affairs section.

(f) Each utility shall keep a record of each informal complaint and of each dispute. The record shall show the name and address of the initiating customer or person applying for service, the date and character of the issue, and the adjustment or disposition made. This record shall be open at all times to inspection by the person who initiated the informal complaint or dispute, by the Commission, and by Commission staff.

3005. Records.

(a) Except as a specific rule may require, every utility shall maintain, for a period of not less than three years, and shall make available for inspection at its principal place of business during regular business hours, the following:

(I) records concerning disputes and informal complaints, which records are created pursuant to rule 3004;

(II) records of daily load and monthly plant output, which records are created pursuant to rule 3201;

(III) records of service voltage measurements, which records are created pursuant to paragraph 3202(a);

(IV) records concerning interruptions of service, which records are created pursuant to rule 3203;

(V) records concerning certification and calibration of meter testing equipment, which records are created pursuant to rule 3303;

(VI) records concerning meter testing upon customer request, which records are created pursuant to rule 3305;

(VII) records concerning meters and their associated testing, which records are created pursuant to rule 3306;

(VIII) customer billing records, which records are created pursuant to paragraph 3401(a);

(IX) customer deposit records, which records are created pursuant to rule 3403;

(X) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 3503(g) and 3504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission; and

(XI) records concerning the utility’s inspection of Qualifying Facilities, which records are created pursuant to paragraphs 3927(c) and (e).

(b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. If the utility maintains a website, it shall also maintain its current and complete tariffs on its website.

(c) Each utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 101, the Uniform System of Accounts, amended as of April 1, 2014. A utility shall maintain its books of accounts and records separately from those of its affiliates.

(d) Each cooperative electric association which is a RUS borrower shall maintain its books of account and records in accordance with the provisions of 7 C.F.R. Part 1767, effective as of May 27, 2008.

(e) Each non-RUS borrower cooperative electric association shall maintain its books of account and records either consistent with the provisions of 18 C.F.R. Part 125, effective as of April 1, 2004, or consistent with the provisions of 7 C.F.R. Part 1767, effective as of May 27, 2008.

(f) Each utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 125, the Preservation of Records of Public Utilities and Licensees, amended as of August 7, 2000.

(g) Each cooperative electric association that is a RUS borrower shall preserve its records in accordance with the provisions of Rural Utilities Service Bulletin 180-2, effective June 26, 2003.

(h) Each non-RUS borrower cooperative electric association shall preserve records consistent with the provisions of 18 C.F.R. Part 101, effective as of April 1, 2014.

3006. Annual Reports and Cooperative Electric Association Reports.

(a) On or before April 30th of each year, each utility shall file with the Commission an annual report for the preceding calendar year. The utility shall submit the annual report on forms prescribed by the Commission; shall properly complete the forms; and shall ensure the forms are verified and signed by a person authorized to act on behalf of the utility; and shall file the forms in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure. If the Commission grants the utility an extension of time to file the annual report, the utility nevertheless shall file with the Commission, on or before April 30, the utility's total gross operating revenue from intrastate utility business transacted in Colorado for the preceding calendar year.

(b) If a certified public accountant prepares an annual report for a utility, the utility either shall file two copies of the report with the Commission or shall file it through the Commission's E-Filings System within 30 days after publication.

(c) A cooperative electric association shall file with the Commission a report listing its designation of service of process.

(d) A cooperative electric association shall file with the Commission a report of election to be governed by § 40-8.5-102, C.R.S., pertaining to unclaimed monies. This report shall be filed within 60 days of the election.

3007. [Reserved].

3008. Incorporation by Reference.

(a) The Commission incorporates by reference 18 C.F.R. Part 101 (as published on April 1, 2014) regarding the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. No later amendments to or editions of 18 C.F.R. Part 101 are incorporated into these rules.

(b) The Commission incorporates by reference 7 C.F.R. Part 1767 (as published on May 27, 2008) regarding the Uniform System of Accounts Prescribed for RUS Electric Borrowers. No later amendments to or editions of 7 C.F.R. Part 1767 are incorporated into these rules.

(c) The Commission incorporates by reference 18 C.F.R. Part 125 (as published on August 7, 2000) regarding the Preservation of Records of Public Utilities and Licensees. No later amendments to or editions of 18 C.F.R. Part 125 are incorporated into these rules.

(d) The Commission incorporates by reference RUS Bulletin 180-2 (as published on June 26, 2003) regarding Record Retention Recommendations for RUS Electric Borrowers. No later amendments to or editions of RUS Bulletin 180-2 are incorporated into these rules.

(e) The Commission incorporates by reference the National Electrical Safety Code, 2012 edition, published by the Institute of Electrical and Electronics Engineers and endorsed by the American National Standards Institute. No later amendments to or editions of the National Electrical Safety Code are incorporated into these rules.

(f) The Commission incorporates by reference 18 C.F.R., Subchapter K, Part 292, Subparts A, B and C (as published on February 21, 2012) regarding §§ 201 and 210 of the Public Utility Regulatory Policies Act of 1978. No later amendments to or editions of 18 C.F.R., Subchapter K, Part 292, Subparts A, B and C are incorporated into these rules.

(g) Any material incorporated by reference in this Part 3 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except when such days are state holidays. . Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: www.govinfo.gov/help/cfr; United States Department of Agriculture Rural Development: www.rd.usda.gov/publications/regulations-guidelines/bulletins/electric; and National Electrical Safety Code: www.standards.ieee.org.

CIVIL PENALTIES

3009. Definitions.

The following definitions apply to rules 3009, 3010, and 3976, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Civil penalty" means any monetary penalty levied against a public utility because of intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.

(b) "Civil penalty assessment" means the act by the Commission of imposing a civil penalty against a public utility after the public utility has admitted liability or has been adjudicated by the Commission to be liable for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders.

(c) "Civil penalty assessment notice" means the written document by which a public utility is given notice of an alleged intentional violation of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders and of a proposed civil penalty.

(d) "Intentional violation." A person acts "intentionally" or "with intent" when his conscious objective is to cause the specific result proscribed by the statute, rule, or order defining the violation.

3010. Regulated Electric Utility Violations, Civil Enforcement, and Enhancement of Civil Penalties.

(a) The Commission may impose a civil penalty in accordance with the requirements and procedures contained in § 40-7-113.5, C.R.S., § 40-7-116.5, C.R.S., and paragraph 1302(b), 4 Code of Colorado Regulations 723-1, for intentional violations of statutes in Articles 1 to 7 and 15 of Title 40, C.R.S., Commission rules, or Commission orders as specified in §§ 40-7-113.5 and 40-7-116.5, C.R.S., and in these rules.

(b) The Director of the Commission or his or her designee shall have the authority to issue civil penalty assessments for the violations enumerated in § 40-7-113.5, C.R.S., subject to hearing before the Commission. When a public utility is cited for an alleged intentional violation, the public utility shall be given notice of the alleged violation in the form of a civil penalty assessment notice.

(c) The public utility cited for an alleged intentional violation may either admit liability for the violation pursuant to § 40-7-116.5(1)(c) or the public utility may contest the alleged violation pursuant to § 40-7-116.5(1)(d), C.R.S. At any hearing contesting an alleged violation, trial staff shall have the burden of demonstrating a violation by a preponderance of the evidence.

(d) In any written decision entered by the Commission pursuant to § 40-6-109, C.R.S., adjudicating a public utility liable for an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order, the Commission may impose a civil penalty of not more than two thousand dollars, pursuant to § 40-7-113.5(1), C.R.S. In imposing any civil penalty pursuant to § 40-7-113.5(1), C.R.S., the Commission shall consider the factors set forth in paragraph 1302(b).

(e) The Commission may assess doubled or tripled civil penalties against any public utility, as provided by § 40-7-113.5(3), C.R.S., § 40-7-113.5(4), C.R.S., and this rule.

(f) The Commission may assess any public utility a civil penalty containing doubled penalties only if:

(I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted an intentional violation of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;

(II) the conduct for which doubled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable; and

(III) the conduct for which doubled civil penalties are sought occurred within one year after conduct for which the public utility has admitted liability by paying the civil penalty assessment, or conduct for which the public utility has been adjudicated by the Commission in an administratively final written decision to be liable.

(g) The Commission may assess any public utility a civil penalty containing tripled penalties only if:

(I) the public utility has admitted liability by paying the civil penalty assessment for, or has been adjudicated by the Commission in an administratively final written decision to be liable for, engaging in prior conduct that constituted two or more prior intentional violations of a statute in Articles 1 to 7 and 15 of Title 40, C.R.S., a Commission rule, or a Commission order;

(II) the conduct for which tripled civil penalties are sought violates the same statute, rule, or order as conduct for which the public utility has either admitted liability by paying the civil penalty assessment or been adjudicated by the Commission in an administratively final written decision to be liable, in at least two prior instances; and

(III) the conduct for which tripled civil penalties are sought occurred within one year after the two most recent prior instances of conduct for which the public utility has either admitted liability by paying the civil penalty assessment, or been adjudicated by the Commission in an administratively final written decision to be liable.

(h) When more than two instances of prior conduct exist, the Commission shall only consider those instances occurring within one year prior to the date of such alleged conduct for which tripled civil penalties are sought.

(i) Nothing in this rule shall preclude the assessment of tripled penalties when doubled and tripled penalties are sought in the same civil penalty assessment notice.

(j) The Commission shall not issue a decision on doubled or tripled penalties until after the effective date of the administratively final Commission decision upon which the single civil penalty was based.

(k) The civil penalty assessment notice shall contain the maximum penalty amount provided by rule for each individual violation noted, with a separate provision for a reduced penalty of 50 percent of the penalty amount sought if paid within ten days of the public utility's receipt of the civil penalty assessment notice.

(l) The civil penalty assessment notice shall contain the maximum amount of the penalty surcharge pursuant to § 24-34-108(2), C.R.S., if any.

(m) A penalty surcharge referred to in paragraph (l) of this rule shall be equal to the percentage set by the Department of Regulatory Agencies on an annual basis. The surcharge shall not be included in the calculation of the statutory limits set in § 40-7-113.5(5), C.R.S.

(n) Nothing in these rules shall affect the Commission's ability to pursue other remedies in lieu of issuing civil penalties.

3011. – 3024. [Reserved].

CUSTOMER DATA ACCESS AND PRIVACY

3025. Scope and Applicability.

The basis and purpose of these rules is to describe the protection of and limited access to customer data for electric utilities over which the Commission has jurisdiction. These rules are applicable to all utilities except for certain provisions as defined in the rule. For the purpose of the Customer Data Access and Privacy Rules, electric utilities are classed into two tiers: a Tier I electric utility serves more than 150,000 electric customers; a Tier II electric utility serves 150,000 or fewer electric customers.

3026. Customer Data.

A utility shall maintain standard customer data sufficient to allow a customer to understand his or her energy usage at a level of detail commensurate with the meter or network technology used to serve the customer.

3027. Privacy, Access, and Disclosure.

(a) A utility shall protect customer data in the utility's possession or control to maintain the privacy of customers, while providing reasonable access to that data. A utility is only authorized to use customer data to provide regulated utility service in the ordinary course of business.

(b) A utility shall not disclose customer data unless such disclosure conforms to these rules, except as required by law or to comply with Commission rule. Illustratively, this includes responses to requests of the Commission, warrants, subpoenas, court orders, or as authorized by § 16-15.5-102, C.R.S.

(c) A utility shall include in its tariffs a description of customer data that the utility is able to provide to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's data within the utility's technological and data capabilities. At a minimum, the utility's tariff must provide the following:

(I) a description of standard customer data and non-standard customer data and the frequency of customer data updates that will be available (annual, monthly, daily, etc.);

(II) the method and frequency of customer data transmittal and access available (electronic, paper, etc.) as well as the security protections or requirements for such transmittal;

(III) a timeframe for processing requests;

(IV) any rate associated with processing a request for non-standard customer data; and

(V) any charges associated with obtaining non-standard customer data.

(d) As part of basic utility service, a utility shall provide access to the customer's standard customer data in electronic machine-readable form, without additional charge, to the customer or to any third party recipient to whom the customer has authorized disclosure of the customer's customer data. Such access shall conform to nationally recognized open standards and best practices. The utility shall provide access in a manner that ensures adequate protections for the utility's system security and the continued privacy of the customer data during transmission.

(e) Nothing in these rules shall limit a customer's right to provide his or her customer data to anyone.

(f) A utility and each of its directors, officers and employees that discloses customer data pursuant to a customer's authorization in accordance with these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of customer data.

3028. Customer Notice.

(a) A utility shall provide each year to its customers a written notice complying with this rule. The utility shall conspicuously post on its website notice of its privacy and security policies governing access to and disclosure of customer data and aggregated data to third parties. This notice shall:

(I) explain what is available to customers, as standard and/or non-standard customer data (e.g., 15 minute versus hourly data);

(II) describe the frequency that the utility can provide customer data based on a request for standard data (e.g., on a weekly or monthly basis);

(III) advise customers that their customer data may provide insight into their activities within the premises receiving service;

(IV) inform customers that the privacy and security of their customer data will be protected by the utility while in its possession;

(V) explain that customers can access their standard customer data, as identified by the utility's tariff, without additional charge;

(VI) advise customers that their customer data will not be disclosed to third parties, except:

(A) as necessary to provide regulated utility services to the customers;

(B) as otherwise permitted or required by law or Commission rule; or

(C) pursuant to the authorization given by the customer in accordance with these rules.

(VII) describe the utility's policies regarding how a customer can authorize access and disclosure of his or her customer data to third parties. With regard to such third party data disclosure, the notice shall:

(A) inform customers that declining a request for disclosure of customer data to a third party will not affect the provision of utility service that the customer receives from the utility; and

(B) explain that any customer consent for access to, disclosure of, or use of a customer's customer data by a third party may be terminated or limited by the customer of record at any time and inform the customers of the process for doing so.

(VIII) explain that aggregated data does not contain customer identifying information and inform customers that customer data may be used to create aggregated data that will not contain customer identifying information;

(IX) explain that the utility may provide aggregated data to third parties, subject to its obligation under paragraph 3033(a);

(X) be viewable on-line and printed in ten point or larger font;

(XI) be sent either separately or included as an insert in a regular monthly bill, or, for those customers who have consented to receive e-bills, such notice may be sent electronically separately from an e-bill, conspicuously marked and stating clearly that important information on the utility's privacy practices is contained therein;

(XII) be available in English and Spanish. The customer notice may also be translated to a language other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be executed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If the utility incurs a cost for translation made at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost; and

(XIII) provide a customer service phone number and web address where customers can direct additional questions or obtain additional information regarding their customer data, the disclosure of customer data or aggregated data, or the utility's privacy policies and procedures with respect to customer data or aggregated data.

3029. Customer Consent Form for the Disclosure of their Customer Data to Third Party Recipients by a Utility.

(a) A utility shall make available to any third party a consent form for the disclosure of customer data that is maintained by the Commission and available from the Commission's website. The form shall be available electronically from the utility. The consent form shall be provided in a non-electronic format by a utility upon request from a customer or third party.

(b) In addition to the Commission supplied form, a utility may create and make available a consent form that:

(I) includes the same information contained in the annual notice provided pursuant to subparagraphs 3028(a)(V), (VI), (VII), and (XIII);

(II) provides spaces for the following required information regarding the third party recipient of the customer data:

(A) the name, including trade name if applicable, physical address, mailing address, e-mail address, and telephone number;

(B) the uses of the data for which the customer is allowing disclosure;

(C) the time period (e.g., months, years) for which data are being requested;

(D) the description of the data that are being requested;

(III) states that the consent is valid until terminated;

(IV) states that the customer must notify the utility service provider in writing (electronically or non-electronically) to terminate the consent including appropriate utility contact information;

(V) states any additional terms except an inducement for the customer's disclosure;

(VI) be viewable on-line and printed in ten point or larger font; and

(VII) provides notice to the customer that the utility shall not be responsible for monitoring or taking any steps to ensure that the third party to whom the data is disclosed is maintaining the confidentiality of the data or using the data as intended by the customer.

(c) A utility may make available an electronic customer consent process for disclosure of customer data to a third party (e.g., a utility controlled web portal) that authenticates the customer identity. The contents of the electronic consent process must generally follow the format of the model consent to disclose customer data form, be clear, and include the elements to be provided pursuant to paragraph (a) of this rule. No utility is required to provide an electronic consent process in a language other than English.

(d) A utility may make available an in-person consent process for disclosure of customer data.

(e) A consent form may be submitted to the utility through electronic or non-electronic methods.

(f) The scope of consent given shall be defined by the terms of the consent form, except that changes of contact names for an organization, trade name, or utility over time do not invalidate consent as to the respective organization, trade name, or utility. Because the contact named for an organization, trade name, or utility is a representative of the respective organization, trade name, or utility, consent terminates as to such contact when the relationship with the organization, trade name, or utility terminates. Modifications to the consent form over time do not invalidate previous consent. Consent need not be provided on new forms so long as the data provided remains within the scope of consent.

(g) Customer consent forms shall be available in English and Spanish. Customer consent forms may be translated into languages other than English or Spanish by a third party or the utility. Forms translated to other languages in accordance with this rule must be accepted by utilities, and may be relied upon, after the English version of the form, the translated version of the form, and an affidavit attesting to the accurate and complete translation from the English version of the form, have been provided to the Commission and the utility possessing the data. Such affidavit must be signed by an interpreter on the active roster of interpreters maintained by the Office of Language Access of the Colorado Judicial Branch. If a utility incurs a cost for a translation at the request of a third party, it may charge the requestor for such cost and may include a reasonable administrative fee in addition to the translation cost.

(h) Any customer consent forms made available from the Commission's website shall be presumed to comply with these rules.

3030. Access to Customer Data for the Provision of Regulated Utility Service.

(a) A utility may disclose customer data to a contracted agent, provided that the contract requires the agent to:

(I) implement and maintain data security procedures and practices to protect the customer data from unauthorized access, destruction, use, modification, or disclosure that are equal to or greater than the data privacy and security policies and procedures used by the utility internally to protect customer data;

(II) use customer data solely for the purpose of the contract and prohibit the use of customer data for a secondary commercial purpose not related to the purpose of the contract without first obtaining the customer's consent as provided for in these rules;

(III) return to the utility or destroy any customer data that is no longer necessary for the purpose for which it was transferred; and

(IV) execute a non-disclosure agreement with the utility.

(b) The utility shall maintain records of the disclosure of customer data to contracted agents for a minimum of three years. Such records shall include all contracts with the contracted agent and executed non-disclosure agreements.

3031. Local Government Access to Customer Data from a Utility for Audit.

(a) A utility may disclose customer data to a local government either with an audit required to be provided pursuant to a final Commission decision (e.g., a decision approving a franchise agreement) or as reasonably necessary for an audit conducted by a governmental entity of franchise fees paid to them by the utility, provided that:

(I) disclosure is not otherwise prohibited by a final Commission decision (e.g., Commission-approved franchise between the utility and the local government);

(II) disclosure is made to a designated auditor or auditor's office, who is either an employee or agent of the local government;

(III) the auditor collects and uses the customer data solely for the purpose of reviewing or conducting the audit and is prohibited from disclosing or using the customer data for a purpose not related to the audit;

(IV) the local government implements and maintains data security procedures and practices to protect the customer data from unauthorized access, destruction, use, or modification;

(V) the local government destroys or returns to the utility any customer data no longer necessary for the purpose for which it was transferred unless state law or the municipality's state-mandated retention schedule requires otherwise;

(VI) the local government agrees not to permit access to the data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants;

(VII) the local government agrees that any recipient of the data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility;

(VIII) governing law or a non-disclosure agreement executed with the utility requires that the local government, at a minimum, comply with the requirements of this rule; and

(IX) the data requested is for utility customers served in the boundaries of the local government.

(b) The utility shall maintain records of all disclosures of customer data to local government requestors for a minimum of three years.

(c) Availability of customer data pursuant to this rule does not preclude a local government from requesting other data reports.

3032. Third Party Access to Customer Data from a Utility.

(a) Except as provided in this rule, paragraph 3027(b), rule 3030, and rule 3031, a utility shall not disclose customer data to any third party unless the customer or a third party acting on behalf of a customer submits a paper or electronic signed consent to disclose customer data form that has been executed by the customer of record.

(b) Incomplete or non-compliant consent to disclose customer data forms are not valid and shall be rejected by the utility.

(c) The utility shall maintain records of all of the disclosures of customer data to third party requestors. Such records shall include a copy of the customer's signed consent to disclose customer data form all identifying documentation produced by the third party requestor, the customer's agreed upon terms of use, the date(s) and frequency of disclosure, and a description of the customer data disclosed.

(d) The utility shall maintain records of customer data disclosures for a minimum of three years and shall make the records of the disclosure of a customer's customer data available for review by the customer within five business days of receiving a paper or electronic request from the customer, or at such greater time as is mutually agreed between the utility and the customer.

3033. Requests for Aggregated Data Reports from a Utility.

(a) A utility shall not disclose aggregated data unless the recipient is authorized to receive all customer data within the aggregated data, that the disclosure otherwise conforms to this rule and rules 3031, 3034, and 3035. In aggregating customer data to create an aggregated data report, a utility must ensure the data does not include any personal information or a unique identifier.

(b) At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report (the "15/15 Rule").

(c) If an aggregated data report cannot be generated in compliance with paragraph 3033(b), the utility shall notify the requestor that the aggregated data, as requested, cannot be disclosed and identify the reason(s) the request was denied. The requestor shall be given an opportunity to revise its aggregated data request in order to address the identified reason(s). An aggregated data request may be revised by expanding the number of customers or premise accounts in the request, expanding the geographic area included in the request, combining different customer classes or rate categories, or other applicable means of aggregating.

(d) A utility shall include in its tariffs a description of standard and non-standard aggregated data reports available from the utility to any requestor. At a minimum, the utility's tariff shall provide the following:

(I) a description of standard and non-standard aggregated data reports available from the utility including all available selection parameters (customer data or other data);

(II) the frequency of data collection (annual, monthly, daily, etc.);

(III) the method of transmittal available (electronic, paper, etc.) and the security protections or requirements for such transmittal;

(IV) the charge for providing a standard aggregated data report or the hourly charge for compiling a non-standard aggregated data report;

(V) the timeframe for processing requests; and

(VI) a request form for submitting a data request for aggregated data reports to the utility identifying any information necessary from the requestor in order for the utility to process the request.

(e) If a utility is unable to fulfill a non-standard aggregated data report request because it does not have and/or does not elect to or cannot obtain all of the data the requestor wishes to include in the aggregated data report, then the utility may contract with a contracted agent to include the additional data and process it along with the customer data in the utility's possession, to generate a non-standard aggregated data report.

(f) A utility and each of its directors, officers and employees that discloses aggregated data as provided in these data privacy rules shall not be liable or responsible for any claims for loss or damages resulting from the utility's disclosure of aggregated data.

(g) A utility shall not provide aggregated customer data in response to multiple overlapping requests from or on behalf of the same requestor that have the potential to identify customer data.

3034. Property Owner Request for Whole Building Energy Use Data from a Utility.

(a) If requested by a property owner or its authorized agent, a Tier I utility shall provide whole building energy use data to the property owner or its authorized agent so long as:

(I) the whole building energy use data contains at least four customers or tenants, which may include the property owner's own account; and no single customer's customer data, unless it is the property owner's, comprises more than 50 percent of the whole building energy use data used to generate the whole building energy use data report;

(II) the property owner agrees to not disclose the whole building energy use data except for the purposes of building benchmarking, identifying energy efficiency projects, and energy management; and

(III) the property owner signs a non-disclosure agreement with the utility requiring the property owner, at a minimum to:

(A) take appropriate administrative, technical, and physical safeguards to protect the whole building data from any unauthorized use or disclosure to protect the data from unauthorized access, destruction, use, modification, or disclosure;

(B) only use the whole building energy use data for the purposes of building benchmarking, identifying energy efficiency projects, energy management, and complying with laws or ordinances;

(C) agree to not attempt to determine an individual utility customer's energy use from the whole building energy use data and not to use the information to contact the subject of the information;

(D) agree to not use the whole building energy use data for a secondary commercial purpose not related to the authorized purpose without first obtaining the customer's consent as provided for in these rules;

(E) destroy any whole building energy use data that is no longer necessary for the purpose for which it was transferred;

(F) agree not to permit access to the whole building data by anyone that has not agreed to abide by the terms pursuant to which the data was provided by the utility. This includes, but is not limited to, all interns, subcontractors, staff, other workforce members, and consultants; and

(G) agree that any recipient of the whole building data pursuant to this rule does not obtain any right, title or interest in any of the data provided by the utility.

(b) Upon request by a property owner or its authorized agent, a Tier II utility shall provide whole building energy use data upon the same conditions to the extent of, and based upon, information available in the ordinary course of business.

(c) A utility shall provide a requested whole building energy use data report in electronic, machine readable format that conforms to nationally recognized open standards and best practices.

(d) A utility may charge a property owner or its authorized agent for the development of a whole building energy use data report. Such rate shall be determined in a utility tariff as a non-standard aggregated data report. Alternatively, the utility need not charge the customer if the cost to charge a property owner or its authorized agent is greater than the cost to develop a whole building energy use data report.

(e) Availability of whole building energy use data pursuant to this rule does not preclude a property owner from requesting other data reports.

3035. Community Energy Reports

(a) A Tier I utility shall generate a community energy report for each local government, other than a Colorado county, included in its service territory with 50,000 or more residents. A Tier I utility shall generate a community energy report for each Colorado county included in its service territory with 100,000 or more residents. Any local government with fewer than 50,000 residents and Colorado county with fewer than 100,000 residents or a minority of whom are served by a Tier I utility shall be treated as if it had 50,000 or more residents served by the Tier I upon request from the local government or county. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. All population thresholds shall be based on the most recent population estimate from the Colorado State Demography Office and where the utility serves the majority of the population.

(b) On or before June 1 of every year, a Tier I utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.

(c) The community energy report shall include the following information or aggregated data for the utility and its customers and specific to the local government for the prior calendar year:

(I) the annual kilowatt hours consumed by customers, provided by residential, commercial, and industrial classes, and street lighting;

(II) the average number of customers in the residential, commercial, industrial class, and street lighting;

(III) the utility's emissions factor;

(IV) the utility's electric generation resource mix;

(V) the total capacity of retail renewable distributed generation (as defined at paragraph 3652(ff)) installed in the local government's jurisdiction and the total annual kilowatt hours produced from that generation; and

(VI) the total annual energy saved (in kilowatt hours) from energy efficiency measures installed.

(d) A local government may submit, or have another local government submit on its behalf, GIS data to define its jurisdictional boundaries prior to the issuance of the community energy report.

(e) Upon request by a local government, a Tier II utility shall generate a community energy report, in accordance with this rule, consistent with the utility's meter, network, or data capabilities. Such requests shall be made by January 31 of the calendar year following the reporting year and shall continue in effect until such time as the request is withdrawn or cancelled by the local government. On or before June 1 of every year, the utility shall make publicly available for download all community energy reports generated for the prior year. Reports shall be available in an electronic machine-readable form that conforms to nationally recognized open standards and best practices.

(f) Availability of the community energy report pursuant to this rule does not preclude a local government from requesting other data reports.

3036. – 3099. [Reserved].

OPERATING AUTHORITY

3100. Certificate of Public Convenience and Necessity for a Franchise.

(a) A utility seeking authority to provide service pursuant to a franchise shall file an application pursuant to this rule. When a utility enters into a franchise agreement with a municipality for the first time, it shall obtain authority from the Commission pursuant to § 40-5-102, C.R.S. prior to providing service under that initial franchise agreement. A utility maintains the right and obligation to serve a municipality within its service territory after the expiration of any franchise agreement.

(b) An application for certificate of public convenience and necessity to exercise franchise rights shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the information required in paragraphs 3002(b) and 3002(c);

(II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;

(III) a statement describing the franchise rights proposed to be exercised. The statement shall include a description of the type of utility service to be rendered and a description of the city or town sought to be served;

(IV) a certified copy of the franchise ordinance; proof of publication, adoption, and acceptance by the applying utility; a statement as to the number of customers served or to be served and the population of the city or town; and any other pertinent information;

(V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the authority sought;

(VI) a copy of a feasibility study for areas previously not served by the applying utility, which study shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study; and

(VII) a statement of the names of public utilities and other entities of like character providing similar service in or near the area sought to be served.

3101. Certificate of Public Convenience and Necessity for Service Territory.

(a) A utility seeking authority to provide service in a new service territory shall file an application pursuant to this rule. A utility cannot provide service to a new geographic area without authority from the Commission, unless the utility extends its facilities and service:

(I) within a city and county or city or town within which the utility has lawfully commenced operations;

(II) into territory contiguous to the utility's facility, line, plant, or system that is not served by a public utility providing the same commodity or service; or

(III) within or to territory already served by the utility and the extension is necessary in the ordinary course of business.

(b) An application for certificate of public convenience and necessity to provide service in a new territory shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the information required in paragraphs 3002(b) and 3002(c);

(II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application;

(III) a description of the type of utility service to be rendered and a description of the area sought to be served;

(IV) a map showing the specific geographic area that the applying utility proposes to serve. If the applying utility intends to phase in service in the territory over time, specific areas and proposed in-service dates shall be included. The map shall describe the geographic areas in section, township, and range convention;

(V) a statement describing in detail the extent to which the applying utility is an affiliate of any other utility which holds authority duplicating in any respect the territory sought;

(VI) a statement of the names of public utilities and other entities of like character providing similar service in or near the area involved in the application; and

(VII) a copy of a feasibility study for the proposed area to be served, which shall at least include estimated investment, income, and expense. An applying utility may request that its most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows be submitted in lieu of a feasibility study.

3102. Certificate of Public Convenience and Necessity for Facilities.

(a) A utility seeking authority to construct and to operate a facility or an extension of a facility pursuant to § 40-5-101, C.R.S., shall file an application pursuant to this rule. The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business. The utility shall apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is not in the ordinary course of business.

(b) An application for certificate of public convenience and necessity to construct and to operate facilities or an extension of a facility pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attached exhibits:

(I) The information required in rules 3002(b) and 3002(c).

(II) A statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities.

(III) A description of the proposed facilities to be constructed.

(IV) Estimated cost of the proposed facilities to be constructed. If the facility is a transmission facility, the estimated costs shall be itemized as land costs, substation costs, and transmission line costs.

(V) Anticipated construction start date, construction period, and in-service date.

(VI) A map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries.

(VII) As applicable, electric one-line diagrams.

(VIII) As applicable, information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives.

(IX) As applicable, a report of prudent avoidance measures considered and justification for the measures selected to be implemented.

(X) For transmission construction or extension, the utility shall also comply with rule 3206.

(c) For an application for a certificate of public convenience and necessity for construction or extension of transmission facilities, the applying utility shall describe its actions and techniques relating to cost-effective noise mitigation with respect to the planning, siting, construction, and operation of the proposed transmission construction or extension. The applying utility shall provide computer studies which show the potential noise levels expressed in db(A) and measured at the edge of the transmission line right-of-way. These computer studies shall be the output of utility standard programs, such as EPRI's EMF Workstation 2.51 ENVIRO Program -- Bonneville Power Administration model. The steps and techniques may include, without limitation, the following:

(I) Bundled conductors.

(II) Larger conductors.

(III) Design alternatives considering the spatial arrangement of phasing of conductors.

(IV) Corona-free attachment hardware.

(V) Conductor quality.

(VI) Handling and packaging of conductor.

(VII) Construction techniques.

(VIII) Line tension.

(d) For an application for a certificate of public convenience and necessity for construction or extension of transmission facilities, the applying utility shall describe its actions and techniques relating to prudent avoidance with respect to planning, siting, construction, and operation of the proposed construction or extension. As used in this paragraph, "prudent avoidance" means the striking of a reasonable balance between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure, by taking steps to reduce the exposure at reasonable or modest cost. The steps and techniques may include, without limitation, the following:

(I) Design alternatives considering the spatial arrangement of phasing of conductors.

(II) Routing lines to limit exposures to areas of concentrated population and group facilities such as schools and hospitals.

(III) Installing higher structures.

(IV) Widening right of way corridors.

(V) Burying lines.

(e) To the extent the information is known or can be estimated with a reasonable degree of certainty at the time the application is filed, an application for a certificate of public convenience and necessity for construction or expansion of generation facilities, including but not limited to pollution controls or fuel conversion upgrades and conversion of existing coal-fired plants to natural gas plants, must contain the following information regarding "best value" employment metrics:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

(f) If the information regarding best employment value metrics specified in paragraph 3102(e) is not known at the time an application for a certificate of public convenience and necessity is filed because the applicant has not yet entered into contracts for construction or expansion of the generation facilities for which a CPCN is sought (proposed project), then in the application the applicant shall state that, for the proposed project, it will obtain the information regarding best value employment metrics specified in paragraph 3102(e) from potential contractors through whatever means the applicant uses to select contractors for project construction. If one or more contracts are awarded for the proposed project, then, within 45 days after the last contract is awarded, the applicant shall file in the application proceeding a status report that contains for each contract the information obtained from the contractor with which the utility has entered into a contract (selected contractor) regarding how the selected contractor meets best value employment metrics. Any party may file in the application proceeding comments on this status report within 15 days of the filing of the status report with the Commission. The status report and comments are informational and, absent a Commission order, do not reopen the application proceeding. The utility may file any information regarding a selected contractor's wages on a highly confidential basis.

3103. Certificate Amendments for Changes in Service, in Service Territory, or in Facilities.

(a) A utility seeking authority to do the following shall file an application pursuant to this rule: amend a certificate of public convenience and necessity in order to extend, to restrict, to curtail, or to abandon or to discontinue without equivalent replacement any service, service area, or facility. A utility shall not extend, restrict, curtail, or abandon or discontinue without equivalent replacement, any service, service area, or facility not in the ordinary course of business without authority from the Commission.

(b) An application to amend a certificate of public convenience and necessity in order to change, to extend, to restrict, to curtail, to abandon, or to discontinue any service, service area, or facility without equivalent replacement shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) all information required in paragraphs 3002(b) and 3002(c);

(II) if the application for amendment pertains to a certificate of public convenience and necessity for facilities, all of the information required in rule 3102;

(III) if the application for amendment pertains to a certificate of public convenience and necessity for franchise rights, all of the information required in rule 3100;

(IV) if the application for amendment pertains to a certificate of public convenience and necessity for service territory, all of the information required in rule 3101;

(V) if the application for amendment pertains to a service, the application shall include:

(A) the requested effective date for the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement of the service; and

(B) a description of the extension, restriction, curtailment, or abandonment or discontinuance without equivalent replacement sought. This shall include maps, as applicable. This shall also include a description of the applying utility's existing operations and general service area.

(c) Customer notice of application. In addition to complying with the notice requirements of the Commission's Rules Regulating Practice and Procedure, a utility applying to curtail, restrict, abandon or discontinue service without equivalent replacement shall prepare a written notice as provided in subparagraphs 3002(d)(I) - (XII) and shall mail or deliver the notice at least 30 days before the application's requested effective date to each of the applying utility's affected customers. The customer notice shall include a statement detailing the requested restriction, curtailment, or abandonment or discontinuance without equivalent replacement.

(d) If no customers will be affected by the grant of the application, the notice must meet the requirements of subparagraphs 3002(d)(I) – (XII) and shall be mailed to the Board of County Commissioners of each affected county, and to the mayor of each affected city, town, or municipality.

3104. Transfers, Controlling Interest, and Mergers.

(a) A utility seeking authority to do any of the following shall file an application pursuant to this rule: transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in a utility, whether the transfer of control is effected by the transfer of assets, by the transfer of stock, by merger or by other form of business combination; or transfer assets subject to the jurisdiction of the Commission outside the normal course of business. A utility cannot transfer a certificate of public convenience and necessity; transfer or obtain a controlling interest in any utility; or transfer assets outside the normal course of business without authority from the Commission.

(b) An application to transfer a certificate of public convenience and necessity, to transfer or obtain a controlling interest in a utility, or to transfer assets subject to the jurisdiction of the Commission shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the information required in paragraphs 3002(b) and 3002(c), as pertinent to each party to the transaction;

(II) a statement showing accounting entries, under the Uniform System of Accounts, including any plant acquisition adjustment, gain, or loss proposed on the books by each party before and after the transaction which is the subject of the application;

(III) any agreement for merger, sales agreement, or contract of sale pertinent to the transaction which is the subject of the application;

(IV) facts showing that the transaction which is the subject of the application is not contrary to the public interest;

(V) an evaluation of the benefits and detriments to the customers of each party and to all other persons who will be affected by the transaction which is the subject of the application; and

(VI) a comparison of the kinds and costs of service rendered before and after the transaction which is the subject of the application.

(c) An application to transfer a certificate of public convenience and necessity, an application to transfer assets subject to the jurisdiction of the Commission, or an application to transfer or obtain control of the utility may be made by joint or separate application of the transferor and the transferee.

(d) When control of a utility is transferred to another entity, or the utility's name is changed, the utility which will afterwards operate under the certificate of public convenience and necessity shall file with the Commission a tariff adoption notice, shall post the tariff adoption notice in a prominent public place in each local office and principal place of business of the utility, and shall have the tariff adoption notice available for public inspection at each local office and principal place of business. Adoption notice forms are available from the Commission. The tariff adoption notice shall contain all of the following information:

(I) the name, phone number and complete address of the adopting utility;

(II) the name of the previous utility;

(III) the number of the tariff adopted and the description or title of the tariff adopted;

(IV) the number of the tariff after adoption and the description or title of the tariff after adoption; and

(V) unless otherwise requested by the applying utility in its application, a statement that the adopting utility is adopting as its own all rates, rules, terms, conditions, agreements, concurrences, instruments, and all other provisions that have been filed or adopted by the previous utility.

3105. Securities and Liens.

(a) Subject to the exception contained in paragraph (h) of this rule, a utility which either derives more than five percent of its consolidated gross revenues in Colorado as a public utility or derives a lesser percentage if its revenues are earned by supplying an amount of energy which equals five percent or more of Colorado's consumption shall file an application for Commission approval of any proposal to issue or to assume any financial security or to create a lien.

(b) An application for the issuance or assumption of securities with a maturity of 12 months or more or to create a lien shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) all information required in paragraphs 3002(b) and 3002(c);

(II) the resolution of the applying utility's board of directors approving the issuance, renewal, extension, or assumption of the securities or to create a lien, together with, as applicable and available, the proposed indenture requirements, the mortgage note, the amendment to the loan contract, and the contract for sale of securities or creation of a lien;

(III) a statement describing all short-term and long-term indebtedness outstanding on the date of the most recent balance sheet;

(IV) a statement describing the classes and amounts of capital stock authorized by the articles of incorporation and the amount by each class of capital stock outstanding on the date of the most recent balance sheet;

(V) a statement of capital structure showing common equity, long-term debt, preferred stock, if any, and pro forma capital structure on the date of the most recent balance sheet giving effect to the issuance of the proposed securities. Debt and equity percentages to total capitalization, actual and pro forma, shall be shown;

(VI) a statement of the amount and rate of dividends declared and paid, or the amount and year of capital credits assigned and capital credits refunded, during the previous four calendar years including the present year to the date of the most recent balance sheet;

(VII) a statement describing the type and amount of securities to be issued; the anticipated interest rate or dividend rate; the redemption or sinking fund provisions, if any; and, within ten days of their filing with the Securities and Exchange Commission, the registration statement, related forms, and preliminary prospectus filed with the Securities and Exchange Commission relating to the proposed issuance;

(VIII) a statement of proposed uses, including construction, to which the funds will be or have been applied and a concise statement of the need for the funds; and

(IX) a statement of the estimated cost of financing.

(c) For applications for the creation of a lien on the applying utility's property situated within the State of Colorado where the creation of the lien is not related to the issuance or assumption of a financial security, the application shall also include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) a description of the property which will be subject to the lien;

(II) the amount of the lien;

(III) the proposed use of the funds to be received from the lien;

(IV) the estimated cost for the creation of the lien;

(V) the anticipated duration of the lien;

(VI) the anticipated release date of the lien;

(VIII) the retirement payment plan to release the lien;

(IX) a description of how the applying utility will ensure that neither the creation of the lien nor the use of the proceeds will violate § 40-3-114, C.R.S.;

(X) a statement that, for the duration of the lien, the applying utility will advise the Commission within ten days of any bankruptcy, foreclosure, or liquidation proceeding; and

(XI) a statement that the applying utility will advise the Commission within ten days of any deviation from its lien retirement payment plan.

(d) The Commission shall give notice of the application, which shall set a ten-day intervention period and a hearing date.

(e) Customer notice. In addition to the requirements of subparagraphs 3002(d)(I) – (XII), the notice shall include the address of the applicant.

(f) The applying utility shall file with the Commission the published notice and an affidavit of publication as soon as possible after the filing of the application. The Commission shall not grant the application without a filed notice and the affidavit of publication.

(g) The Commission shall give priority to an application made pursuant to this rule and shall grant or deny the application within 30 days after filing, unless the Commission, for good cause shown, enters an order granting an extension and stating fully the facts necessitating the extension. The Commission shall approve or disapprove an application made pursuant to this rule by written order.

(h) Pursuant to § 40-1-104, C.R.S., a utility may issue, renew, extend or assume liability on securities, other than stocks, with a maturity date of not more than 12 months after the date of issuance, whether secured or unsecured, without application to or order of the Commission provided that no such securities so issued shall be refunded, in whole or in part, by any issue of securities having a maturity of more than 12 months except on application to and approval of the Commission.

(i) Any financial security requiring Commission approval, but issued or assumed without such approval, shall be void.

3106. Flexible Regulation to Provide Jurisdictional Service Without Reference to Tariffs.

(a) A utility seeking authority to provide a jurisdictional service without reference to a tariff shall file an application pursuant to this rule. A utility cannot provide a jurisdictional service without reference to a tariff without authority from the Commission.

(b) An application for flexible regulation to provide jurisdictional service without reference to tariffs shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) all information required in paragraphs 3002(b) and 3002(c);

(II) the name of the customer or potential customer;

(III) a description of the jurisdictional service or services which the applying utility seeks to provide to a customer or a potential customer;

(IV) a description of the manner in which the applying utility will provide the jurisdictional service or services if it contracts with a customer or potential customer;

(V) the facts (not conclusory statements) which the applying utility believes satisfy the requirements of § 40-3-104.3(1)(a), C.R.S.; and

(VI) a statement that the applying utility has provided, or will provide when available, the application and contract as required by paragraph (c) of this rule.

(c) The contract which is the subject of the application shall be filed when available with the Commission under seal pursuant to rules 1100 – 1102 and § 40-3-104.3(1)(b), C.R.S. The applying utility shall furnish the application and, when it is available, of the contract, under seal, to the OCC. Unless the applying utility requests other treatment, the Commission and the OCC shall treat the contract as confidential. If the Commission grants a protective order preserving the confidentiality of the contents of an application, then the applying utility shall also furnish a non-confidential version of the application without the contract to any utility then providing service to the customer or potential customer.

(d) The direct testimony and attachments to be offered at hearing shall accompany the application unless the applying utility believes that the application will be uncontested and unopposed. If an attachment is large or cumbersome, the applying utility shall file the attachment with the Commission; shall provide, for the benefit of the intervenors, the title of the attachment and a summary of the information contained in the attachment; and shall state the location (other than the Commission) at which parties may inspect the attachment.

(e) Prefiled testimony shall not be modified once filed unless the modification is to correct typographical errors or misstatements of fact or unless all parties to the proceeding agree to the modification. In the event a substantive modification is made without the agreement of all parties, the Commission may consider the effect of the substantive modification as a basis for a motion to continue in order to allow the Commission staff or any other party a reasonable opportunity to investigate and, if necessary, to address the modification.

(f) The Commission shall give notice of the application. Any person desiring to intervene in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule shall move to do so within five days of the date the Commission provides notice.

(g) Within five days of receiving written notice of an intervention in a proceeding initiated pursuant to § 40-3-104.3, C.R.S., and this rule, the applying utility shall hand-deliver or otherwise provide to the intervenor a non-confidential version of the application and the applying utility's prefiled testimony.

(h) Unless the Commission orders otherwise, the applying utility shall publish notice of the application in a newspaper of general circulation within three days of the filing of the application.

(i) The notice provided by the applying utility shall include the following information, in addition to the information required by subparagraphs 3002(d)(I) – (XII):

(I) the address of the applying utility;

(II) the name of the customer(s) or potential customer(s) involved;

(III) a statement that the identified customer(s) or potential customer(s) may have the ability to provide its/their own service or may have competitive alternatives available to it/them;

(IV) a general description of the jurisdictional services to be provided;

(V) a statement of where affected customers may call to obtain information concerning the application; and

(VI) a statement that anyone desiring to participate as a party must file a petition to intervene within five days from the date of Commission notice of the application and that the intervention must comport with the Commission's Rules Regulating Practice and Procedure.

(j) Within three days of providing notice, the applying utility shall file with the Commission an affidavit showing proof of publication of notice.

(k) On a case-by-case basis, the Commission may require the applying utility to provide additional information.

(l) Should an application be filed which the Commission determines is not complete, the Commission or Commission staff shall notify the applying utility within seven days from the date the application is filed of the need for additional information. The applying utility may then supplement the application so that it is complete. Once the application is complete, the Commission will process the application, with all applicable timelines running from the date the application is completed.

(m) The Commission shall issue an order approving or disapproving the application within the time permitted under § 40-3-104.3(1)(b), C.R.S.

(n) At the time of any proceeding in which a utility’s overall rate levels are determined, the Commission shall require the utility to file a fully distributed cost method which segregates investments, revenues, and expenses associated with jurisdictional utility service provided pursuant to contract from other regulated utility operations in order to ensure that jurisdictional utility service provided pursuant to contract is not subsidized by revenues from other regulated utility operations. If revenues from a service provided by a utility pursuant to contract are less than the cost of service for that service, the rates for other regulated utility operations shall not be increased to recover the difference.

(o) The applying utility shall provide final contract or other description of the price and terms of service as specified in § 40-3-104.3(1)(e), C.R.S.

3107. Voluntary Air Quality Improvement Programs pursuant to § 40-3.2-102, C.R.S.

(a) A utility seeking authority for cost recovery of a voluntary air quality improvement program shall file an application pursuant to this rule. The utility cannot recover the cost of a voluntary air quality improvement program without authority from the Commission.

(b) An application for cost recovery of a voluntary air quality improvement program shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) all information required in paragraphs 3002(b) and 3002(c);

(II) the voluntary agreement entered into pursuant § 40-3.2-102(1), C.R.S.;

(III) an analysis demonstrating that the proposed cost recovery mechanism complies with, and does not exceed, the rate impact cap, the total cost cap, and the recovery period limit established in § 40-3.2-102(3), C.R.S.;

(IV) a written acknowledgment that any revenues the applying utility receives from transferring, selling, banking, or otherwise using allowances under title IV of the federal Clean Air Act shall be credited to the applying utility's customers to offset air quality improvement costs if such revenues are a result of a voluntary agreement entered into under part 12 of article 7 of title 25 C.R.S., as required by § 40-3.2-102(4), C.R.S.;

(V) a statement as to whether the applying utility's generating capacity will increase under the voluntary agreement for air quality improvement; and

(VI) a statement as to whether, pursuant to § 40-3.2-102(7), C.R.S., the applying utility intends to seek recovery of a portion of the air quality improvement costs from its wholesale customers and, if it does so intend, whether the applying utility intends to credit its retail customers for air quality improvement costs recovered from wholesale customers.

3108. Tariffs.

(a) A utility shall keep on file with the Commission the following documents pertaining to retail electric service: its current Colorado tariffs, forms of contracts and electric service agreements. These documents, unless filed under seal shall be available for public inspection at the Commission and at the principal place of business of the utility.

(b) All tariffs shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.

(c) Filing and contents of tariff.

(I) In addition to the requirements and contents in rule 1210, the following shall be included in a utility's tariff, as applicable:

(A) information regarding the utility's voltages, pursuant to rule 3202;

(B) information regarding the utility's meter testing equipment and facilities, scheduled meter testing, meter testing records, fees for meter testing upon request, and meter reading, pursuant to rules 3303, 3304, 3305, 3306, and 3309;

(C) information regarding the utility's benefit of service transfer policies, pursuant to paragraph 3401(c);

(D) information regarding the utility's installment payment plans and other plans, pursuant to rule 3404;

(E) information regarding the utility's collection fees or miscellaneous service charges, pursuant to subparagraphs 3404(c)(VI) and (VIII);

(F) information regarding the utility's after-hour restoration fees, pursuant to paragraph 3409(b);

(G) information regarding the utility's renewable energy program pursuant to subparagraphs 3657(a)(III), (V), (VI) and (VII);

(H) information regarding the utility's avoided costs, pursuant to paragraph 3902(b); and

(I) rules, regulations, and policies covering the relations between the customer and the utility.

3109. New or Changed Tariffs.

(a) A utility shall file with the Commission any new or changed tariffs. No new or changed tariff shall be effective unless it is filed with the Commission and either is allowed to go into effect by operation of law or is approved by the Commission.

(b) A utility shall use one of the following processes to seek to add a new tariff or to change an existing tariff.

(I) The utility may file the proposed tariff, including the proposed effective date, accompanied by an advice letter pursuant to rule 1210. The utility shall provide notice in accordance with rule 1207. If the Commission does not suspend the proposed tariff in accordance with rule 1305 prior to the tariff's proposed effective date, the proposed tariff shall take effect on the proposed effective date.

(II) The utility may file an application to implement a proposed tariff on less than 30-days' notice, accompanied by the proposed tariff, including the proposed effective date. The utility shall provide notice in accordance with rule 1207). The application shall include the information required in paragraphs 3002(b) and 3002(c); shall explain the details of the proposed tariff, including financial data if applicable; shall state the facts which are the basis for the request that the proposed tariff become effective on less than 30-days' notice; and shall note any prior Commission action, in any proceeding, pertaining to the present or proposed tariff.

(III) Unless the Commission orders otherwise, a utility shall be permitted to file new tariffs complying with an order of the Commission or updating adjustment clauses previously approved by the Commission on not less than two business days' notice. No additional notice beyond the tariff filing itself shall be required.

3110. Advice Letters.

(a) All advice letter filings shall comply with rule 1210 of the Commission's Rules of Practice and Procedure.

(b) In addition to the requirements and contents in rule 1210, the advice letter shall include the estimated amounts, if any, by which the utility's revenues will be affected, calculated on an annual basis.

(c) Customer notice of advice letter. If the utility is required by statute, Commission rule, or order to provide notice to its customers of the advice letter, such notice shall include the requirements of subparagraph 3002(d)(I) – (XII).

3111. – 3199. [Reserved].

FACILITIES

3200. Construction, Installation, Maintenance, and Operation.

(a) The plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering practice in the electric industry to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

(b) For all electric plant construction or installation, the minimum standard of accepted engineering practice is the edition of the National Electrical Safety Code in effect at the time of commencing construction or installation of the electric plant.

(c) Any utility plant that was constructed or installed, and that is maintained and operated, in accordance with the National Electrical Safety Code in effect at the time of its construction or installation shall be presumed to be in compliance with accepted engineering practice in the electric industry and with the provisions of this rule.

3201. Production Plant Instruments.

Each electric utility shall install such indicating watt meters, watt-hour meters, or other instruments as may be necessary to obtain a daily record of the load and a monthly record of the output of its production plants. Each utility purchasing electrical energy shall install such instruments or meters as may be necessary to furnish full information as to the monthly purchases.

3202. Standard Voltage and Frequency; Applications for Variance.

(a) A utility must make every reasonable effort consistent with good engineering practices to maintain a constant frequency and constant voltage on its facilities at all times.

(b) A utility shall periodically measure and record service voltages maintained at the utility's main service terminals as installed for individual customers or groups of customers. Those service voltages shall be practically constant as follows.

(I) For service rendered under a lighting contract or primarily for lighting purposes, the voltage shall be maintained within five percent above or below the standard stated in the utility’s tariff.

(II) For service rendered under a power contract or primarily for power purposes, the voltage shall be maintained within ten percent above or below the standard stated in the utility’s tariff.

(c) The following shall not be considered a violation of paragraph (b) of this rule.

(I) A temporary variation in voltage in excess of those specified if caused by the operation of power apparatus on a customer's premises which necessarily require large starting currents, provided that only the customer’s premises are affected. If other customers are affected, the utility shall work with the customer causing the variation to resolve the voltage fluctuation/violation problem or problems.

(II) A temporary variation in voltage in excess of those specified if caused by the action of the elements.

(III) A temporary variation in voltage in excess of those specified if caused by infrequent, unavoidable, and short-duration fluctuations due to necessary station or line operations.

(d) If a utility seeks to operate at a greater variation in voltages than permitted by paragraph (b) of this rule, the utility shall file an application for a variance. An application for variance shall include:

(I) all information required in paragraphs 3002(b) and 3002(c);

(II) delineation of the geographic boundaries of the service territory for which the variance is sought;

(III) a statement of the facts (not conclusory statements) which supports the need for the requested variance; and

(IV) a demonstration that the applying utility proposes to provide the best voltage regulation practicable under the circumstances.

(e) The Commission may allow a greater variation of voltage when:

(I) service is furnished directly from a transmission line; or

(II) service is furnished in a limited or extended area where customers are widely scattered and the business done within that area does not justify close voltage regulation (such as individual customers or small groups of customers whose service from a transmission line is incidental).

(f) Each utility's tariff shall include a description of test methods, equipment, and frequency of testing used to determine the voltage of electric service furnished.

(g) Each utility's tariff shall include a description of standard average voltage, or voltages, and frequency, or frequencies, as may be required by:

(I) the utility's distribution system;

(II) the utility's entire system; or

(III) each of the several districts into which the utility's system may be divided.

3203. Interruptions of Service.

(a) Each utility shall keep a record of every service interruption (including, without limitation, forced outages caused by events outside of the utility's control, scheduled outages, or sustained outages) which occurs on its entire system or on a major division of its system. The record shall include at least a statement of the time, the duration, and the cause of any service interruption.

(b) The records of service interruptions and a statement of the utility's operating schedules shall be open at all times to the inspection of the duly authorized representatives of the Commission. The utility shall retain these records for five years.

(c) As used in this rule, "service interruption" means a loss of service consistent with IEEE Standard Number 1366, Guide for Electric Power Distribution Reliability Indices.

3204. Incidents Resulting in Death, Serious Injury or Significant Property Damage.

(a) Each utility shall inform the Commission of all incidents which occur in connection with the operation of its property, facilities, or service and which result in death, serious injury, or significant property damage within two hours (120 minutes) of learning of the incident.

(b) Within 30 calendar days of the incident, the utility shall submit a written report to the Director of the Commission. The report shall contain at least the following information:

(I) date, time, place, and location of the incident;

(II) type of incident;

(III) names of all persons involved; and

(IV) nature and extent of injury and damage.

(c) If the utility conducts an internal investigation of an incident referred to in paragraph (a) above, the utility shall make its report available to the Commission upon request by the Commission. The utility may provide paragraphs (b)(III) and (b)(IV) of this report on a confidential basis under seal.

3205. Construction or Expansion of Generating Capacity.

(a) No utility may commence new construction or an expansion of generation facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a certificate of public convenience and necessity or the Commission issues a certificate of public convenience and necessity for the facility or project. Rural electric cooperatives do not need a certificate of public convenience and necessity for new construction or an expansion of generation facilities provided that such construction or expansion is contained entirely within the cooperative's certificated area. The certificate of public convenience and necessity requirement under subparagraph (b)(II) of this rule applies only to jurisdictional electric utilities subject to resource regulation under Rule 3603 and rate regulation under either Rule 3108 or Rule 3109.

(b) The following shall be deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity:

(I) New construction or expansion of existing generation, which will result in an increase in generating capacity of less than ten megawatts.

(II) A generating plant remodel, or installation of any equipment or building space, required for pollution control systems where the estimated total cost in nominal dollars including, but not limited to, engineering, procurement, construction, and interrelated work for such project is reasonably expected to be less than $50 million. The total estimated project cost below which a project is considered to be in the ordinary course of business shall be reviewed and adjusted annually, as necessary, to account for inflation. Within 14 days after the appropriate information is available, the Director of the Commission shall annually determine and publish the amount of such adjustment based on the percentage change in the United States Bureau of Labor Statistics Consumer Price Index for Denver-Boulder, all items, all urban consumers, or its successor index.

(III) When a certificate of public convenience and necessity is sought for a pollution control system required by a determination of the Colorado Department of Public Health and Environment or an identified law, regulation, or administrative or judicial order, there is a presumption, rebuttable by a preponderance of the evidence, that the public convenience and necessity require such pollution control system. This presumption does not alter or diminish the Commission's duty and authority, including its consideration:

(A) in a CPCN proceeding, of the utility's cost estimate for the proposed pollution control project, and whether the utility should pursue plant retirement (with or without an associated plant replacement) or fuel switching as alternatives to the pollution control project; and

(B) in a subsequent rate proceeding, of the prudence, justness, and reasonableness of costs associated with the pollution control project.

(c) For each new construction or expansion of existing generation that will result in an increase in generating capacity of ten megawatts or more, the electric utility shall submit to the Commission, no later than April 30 of each year, a filing for a determination of which of the utility's proposed new construction or expansions for the next three calendar years, commencing with the year following the filing, are necessary in the ordinary course of business and which require a certificate of public convenience and necessity prior to construction. For each project, the filing shall contain the following:

(I) The name, proposed location, and function or purpose of the project.

(II) The estimated cost of the project and the manner in which it is expected to be financed.

(III) The projected date for the start of construction, the estimated date of completion, and the estimated date of commencement of operation.

(d) The Commission will give notice of each filing made pursuant to paragraph (c) of this rule to all those who it believes may be interested. Any interested person may file comments regarding the projects by May 15.

(e) The Staff shall review the filing and any comments received and shall make recommendations in accordance with the following schedule:

(I) For any new construction or expansion project which is scheduled to begin in the year of the filing or the next calendar year and which will result in an increase in generating capacity of ten megawatts or more, the Staff shall make its recommendations by May 31 of the year in which the filing is made.

(II) For any new construction or expansion project which is scheduled to begin in the second or third calendar year following the year in which the filing is made and which will result in an increase in generating capacity of ten megawatts or more, the Staff shall make its recommendations by August 31 of the year in which the filing is made.

(f) The Commission shall issue its decision in accordance with the following schedule:

(I) For any new construction or expansion project which is scheduled to begin in the calendar year of the filing or in the next calendar year and which will result in an increase in generating capacity of ten megawatts or more, the decision designating each generation project that requires a certificate of public convenience and necessity will be issued by June 30 of the year in which the filing is made.

(II) For any new construction or expansion project which is scheduled to begin in the second or third calendar year following the year in which the filing is made and which will result in an increase in generating capacity of ten megawatts or more, the decision designating each generation project that requires a certificate of public convenience and necessity will be issued by October 31 of the year in which the filing is made.

3206. Construction or Extension of Transmission Facilities.

(a) No utility and no cooperative electric association which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., may commence new construction, or extension of transmission facilities or projects until either the Commission notifies the utility that such facilities or projects do not require a certificate of public convenience and necessity or the Commission issues a certificate of public convenience and necessity. Rural electric cooperatives which have elected to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-103, C.R.S., do not need a certificate of public convenience and necessity for new construction or extension of transmission facilities or projects when such construction or expansion is contained entirely within the cooperative's certificated area.

(b) CPCN requirements for new transmission facilities. New transmission facilities that require a CPCN pursuant to this paragraph are not in the ordinary course of business. However, any utility may request a CPCN for any new transmission facility that does not require a CPCN under this paragraph. All utilities and electric cooperative associations subject to paragraph (a) of this rule shall be required to file a CPCN application for all new transmission facilities that meet one of the following criteria:

(I) Transmission facilities designed at 230 kV or above, even if initially operated at a lower voltage. However, a radial transmission line designed at 230 kV or above that serves a single retail customer and terminates at that customer's premises will not require a CPCN application.

(II) Transmission facilities designed at 115 kV or 138 kV, if:

(A) the facilities do not meet the noise and magnetic field thresholds in paragraphs (e) and (f) of this rule; or

(B) the Commission determines that the facilities are not in the ordinary course of business.

(c) CPCN requirements for extension of transmission facilities. Any utility or electric cooperative association may request a CPCN for an extension of transmission facilities that would not otherwise require an application for a CPCN under this rule. For all utilities and electric cooperative associations subject to paragraph (a) of this rule, the following modifications are not in the ordinary course of business and shall require a CPCN.

(I) Modification to any existing transmission facility that results in an increase in the noise or magnetic field levels and such levels are above the thresholds in paragraphs (e) and (f).

(II) Modification to any existing transmission facility so that it will be operated at a higher voltage, with or without conductor replacement:

(A) unless a CPCN has already been approved for the operation of the transmission facility at the higher voltage; or

(B) unless the upgrade is to a voltage less than 230 kV, and the noise and magnetic field thresholds in paragraphs (e) and (f) are met.

(d) Annual report for planned transmission facilities. No later than April 30 of each year, each electric utility and each cooperative electric association which has voted to exempt itself pursuant to § 40-9.5-103, C.R.S., shall file with the Commission its proposed new construction or extension of transmission facilities for the next three calendar years, commencing with the year following the filing. The filing shall contain a reference to all such proposed new construction or extensions, regardless of whether the utility or cooperative electric association has referenced such new construction or extensions in prior annual filings. Amended filings or filings of an emergency nature are permitted at any time. By submitting the proper information, the report may request a decision that projects are in the ordinary course of business and do not require a CPCN.

(I) The filing shall contain the following information for each project:

(A) the name, proposed location, and function or purpose of the project;

(B) if the project is a substation or related facilities: the voltage level and the MVA rating of transformers and shunt capacitors;

(C) if the project is a transmission line: the voltage, the length in miles, the continuous MVA rating, and the substation termination points;

(D) the alternatives considered by the utility in its transmission planning process including consideration for energy storage systems;

(E) the estimated cost of the project;

(F) the projected date for the start of construction, the estimated date of completion, and the estimated in-service date; and

(G) for new construction or extensions that were included in prior annual filings, an update of the status of, and any changes to, such new construction or extensions. Once a project is reported as completed or cancelled, its status can be removed in subsequent filings.

(II) Review of annual report. Filings made in accordance with this paragraph will be reviewed pursuant to the following schedule.

(A) The Commission will give notice of each filing made pursuant to this rule to all those who it believes may be interested. Any interested person may file comments regarding the projects by June 15.

(B) Commission staff shall review the filing and any comments received and shall make recommendations to the Commission by July 1.

(e) Magnetic fields. This paragraph applies to any application for a CPCN or any filing made pursuant to paragraph (d) of this rule for which the Commission is requested to determine that a project does not require a CPCN. The filing shall include the expected maximum level of magnetic fields that could be experienced under design conditions at the edge of the transmission line right-of-way or substation boundary, at a location one meter above the ground.

(I) For a right-of-way containing a single circuit, the magnetic field level will be presented at the continuous MVA rating of that circuit.

(II) For a right-of-way containing multiple circuits, the magnetic field level will be presented at the maximum pre-outage currents wherein the outage of a single circuit loads the remaining circuits to their continuous MVA rating.

(III) Proposed magnetic field levels of 150 mG (milliGauss) and below are deemed reasonable by rule and need not be mitigated to a lower level. Proposed magnetic field levels above 150 mG will be subject to further review.

(IV) If the magnetic field level for the proposed project is above 150mG, then the filing must present an alternative (e.g., different spatial arrangements of conductors, higher structures, wider rights-of-way, undergrounding lines, etc.), and associated costs, that reduces the magnetic field level to 150 mG. The applicant may also present other alternatives that yield intermediate magnetic field levels for the Commission's consideration.

(V) In the instance when the magnetic field level cannot be reduced to 150mG or below, the filing must present an alternative, and associated costs, that would reduce the magnetic field level to the lowest possible level. The applicant may also present other alternatives yielding intermediate magnetic field levels for the Commission's consideration.

(VI) If either subparagraph (IV) or (V) is applicable, then the filing must also describe the efforts and associated costs to route the line away from concentrated population and group facilities such as schools and hospitals.

(VII) If either subparagraph (IV) or (V) is applicable, the Commission shall weigh the societal, engineering, and economic considerations of the project as proposed and the alternatives presented in determining whether the CPCN should be granted.

(f) Noise. This paragraph applies to any application for a CPCN or any filing made pursuant to paragraph (d) of this rule for which the Commission is requested to determine that a project does not require a CPCN. The filing shall include the projected level of noise radiating beyond the property line or right-of-way (as applicable) at a distance of 25 feet.

(I) The filing shall provide computer studies which show the potential level of noise expressed in db(A). These computer studies shall be the output of utility standard programs, such as EPRI's EMF Workstation 2.51 ENVIRO Program – Bonneville Power Administration model and use the assumption that the proposed facility is operating at its highest continuous design voltage under L50 rain conditions.

(II) Proposed levels of noise at or below the values listed are deemed reasonable by rule and need not be mitigated to a lower level.

(A)	Residential	50 db(A)
(B)	Commercial	55 db(A)
(C)	Light industrial	65 db(A)
(D)	Industrial	75 db(A)

(III) If the zoning designation that has been assigned by the local zoning regulatory agency for a specific segment of the transmission project is not listed in subparagraph (II), the applicant shall reference the noise threshold corresponding to the zoning designation that most closely represents the predominant use of the land in question, with consideration given to the surrounding area. To support its selection of the applicable noise threshold, the applicant shall present information related, among other things, to the projected use of the land and surrounding area in the near term future. However, the noise level will not be subject to further review if the applicant proposes a noise threshold of 50 db(A) or below regardless of the use of the land.

(IV) If the projected level of noise does not meet the threshold limits in subparagraph (II), then the filing must present an alternative (e.g., larger conductors, bundled conductors, different spatial arrangements of conductors, higher structures, wider rights-of-way, etc.) and associated costs, that reduces the level of noise to the proper threshold level. The applicant may also present other alternatives yielding intermediate noise levels for the Commission's consideration.

(V) In the instance where the level of noise cannot be reduced to the threshold levels in subparagraph (II), then the filing must present an alternative and associated costs that would reduce the level of noise to the lowest possible level. The applicant may also present other alternatives yielding intermediate noise levels for the Commission's consideration.

(VI) If either subparagraph (IV) or (V) is applicable, the Commission shall weigh the societal, engineering, and economic considerations of the project as proposed and the alternatives presented in determining whether the CPCN should be granted.

(g) Service connections. The utility shall install and maintain service connections from transmission extensions, which is any construction of transmission facilities and appurtenant facilities, including meter installation facilities (except meters) that is connected to and enlarges the utility's transmission system and is necessary to supply transmission service to one or more additional customers, consistent with conditions contained in the utility's tariff.

(h) Any application for a CPCN or any filing made pursuant to paragraph (d) of this rule for a transmission line project shall explain how the proposed project is consistent with the utility's ten-year transmission plan filed with the Commission pursuant to rule 3627. In its CPCN application, the applicant may rely substantively on the information contained in its most recent ten-year transmission plan and the Commission's decision on the review of the plan to support its application.

3207. Construction or Extension of Distribution Facilities.

(a) Extension of distribution facilities, as authorized in § 40-5-101, C.R.S., is deemed to occur in the ordinary course of business and shall not require a certificate of public convenience and necessity.

(b) Notwithstanding paragraph (a), the utility shall include consideration of energy storage systems in its planning processes as an alternative to construction or extension of distribution facilities where appropriate.

(c) No later than April 30 of each year, each utility shall file with the Commission a report detailing how it has complied with paragraph (b) for the preceding calendar year.

(d) The utility shall install and maintain service connections from distribution extensions, which is any construction of distribution facilities, including primary and secondary distribution lines, transformers, service laterals, and appurtenant facilities (except meters and meter installation facilities) that are necessary to supply service to one or more additional customers, consistent with conditions contained in the utility's tariff.

(e) When a customer or potential customer requests a cost estimate of a distribution line extension, the utility shall provide a photovoltaic system cost comparison, if the following conditions are met:

(I) the customer or potential customer provides the utility with load data (estimated monthly kWh usage) as requested by the utility to conduct the comparison;

(II) the customer or potential customer's peak demand is estimated to be less than 25 KW.

(f) In performing a photovoltaic system cost comparison analysis, the utility will consider line extension distance, overhead/underground construction, terrain, other variable construction costs, and the probability of additions to the line extension within the life of the open extension period.

(g) If the customer or potential customer has a ratio of estimated monthly kWh usage divided by line extension mileage that is less than or equal to 1,000 (i.e., kWh/Mileage is <=1,000), the utility shall provide the photovoltaic system cost comparison at no cost to the customer or potential customer. If the ratio is greater than 1,000, the customer or potential customer shall bear the cost of the comparison, if the cost comparison is requested by the customer or potential customer.

3208. Poles.

(a) In the case of two or more utilities jointly owning or using a pole or pole line structure, each of the utilities shall mark each pole or structure with the initials of its name, abbreviation of its name, corporate symbol, or other distinguishing mark so that the ownership of such structure may be readily and definitely determined.

(b) A utility shall mark each wood pole, post, tower, or other structure used for the support or attachment of electrical conductors, guys, or lamps, with dating nails or similar devices indicating the year in which the structure was installed.

(c) In accordance with prudent utility practices, a utility shall inspect, and shall timely repair or replace, each of the following which it owns or uses: poles, posts, towers, or other structures used for the support or attachment of electrical conductors, guys, or lamps.

(d) The requirements of this rule shall apply to all existing and future erected structures and to all changes in ownership.

3209. Service Connections.

Service connections to customer premises or property involving overhead or underground equipment shall be installed and maintained consistent with the conditions stated in the utility’s tariff. In special cases involving either overhead or underground service connections and as necessary, the Commission will prescribe the proper charge.

3210. Line Extension.

(a) Each utility shall have tariffs which set out its line extension policies, procedures, and conditions.

(b) Specific tariff provisions for making overhead or underground service connections, for transmission line extensions, and for distribution line extensions shall include the following.

(I) Service connections and distribution line extensions by customer class and the appropriate terms and conditions under which those connections and extensions will be made.

(II) Provisions requiring the utility to provide to a customer or to a potential customer, upon request, service connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system.

(III) Provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension.

(IV) Provisions addressing steps to ameliorate the rate and service impact upon existing customers, including equitably allowing future customers to share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including a refund of customer connection or extension payments when appropriate).

(V) A description of specific customer categories (such as permanent, indeterminate, and temporary) within each customer class.

(c) Upon request by a customer or a potential customer, the utility shall conduct a comparison of photovoltaic energy to any proposed distribution line extension if a customer or potential customer provides the utility with load data (estimated monthly kWh usage) requested by the utility to conduct the comparison and if the customer's or potential customer's peak demand is estimated to be less than 25 KW. In performing the comparison analysis, the utility will consider line extension distance, overhead/underground construction, terrain, other variable construction costs, and the probability of additions to the line extension during the life of the open extension period. If the customer has a ratio of estimated monthly kWh usage divided by line extension mileage that is less than or equal to 1,000 (i.e., kWh/Mileage is <=1,000), the utility shall provide the photovoltaic system cost comparison at no cost to the customer or potential customer. If the ratio is greater than 1,000, the customer or potential customer shall bear the cost of the comparison, if the cost comparison is requested by the customer or potential customer.

3211. – 3249. [Reserved].

MAJOR EVENTS REPORTING

The purpose of this section is to provide timely information to the Commission regarding major events on electric systems that result in loss of electric service to its customers. The data gathered pursuant to this section will be for information purposes in order to provide the Commission with an active and current record as to the reliability of the electric systems in Colorado. The intent of these rules is to merely provide the Commission with information which is already compiled by the utilities following a major event on their system.

3250. [Reserved].

3251. Notification to Commission.

Each utility shall notify the Commission of a major event as soon as possible, but in any event no later than the first business day following the major event. The notification of the event should be by e-mail sent to the Chief Engineer of the Fixed Utilities Section of the Commission at the following e-mail address: DORA_PUC_Webmail@state.co.us.

3252. Major Event Report.

(a) Within 15 calendar days after the end of a major event, a utility shall submit a written report to the Director of the Commission.

(b) At a minimum, the report shall include the following.

(I) The date and time when the major event began; the date and time when the utility's control center began treating the situation as a major event; and the date and time when the utility classified the major event as closed.

(II) The total number of customers out-of-service over the course of the major event and the general (by city or district level) area in which the major event occurred.

(III) The total number of affected locations by facility classification.

(IV) The date and time at which any mutual aid and non-utility contractor crews were requested; the date and time when each such crew arrived for duty; the date and time when each such crew was released from duty; and the non-utility contractor response(s) to the request(s) for assistance.

(V) A timeline profile on the number of utility line crews, mutual aid crews, and non-utility contractor line and tree crews working on restoration activities during the major event.

(VI) Identification of the cause(s) of the major event and of the factors which contributed to the major event.

(VII) A listing of each new or existing policy, procedure, and guideline which the utility will implement or has implemented in order to prevent a similar major event or recurrence of the major event in the future.

(VIII) An affidavit of an officer of the utility, which affidavit verifies the information in the report.

3253. Supplemental or Additional Major Event Reporting.

(a) With respect to generation and transmission disturbances, utilities shall provide to Commission staff, on a confidential basis, any reports required by the Western Electricity Coordinating Council.

(b) With respect to generation and transmission disturbances, utilities shall provide to Commission staff, on a confidential basis, any Emergency Incident and Disturbance Reports filed with the Energy Information Administration of the United States Department of Energy on significant transmission or generation disturbances.

(c) At such time and in such form as the Commission may require, each utility shall furnish to the Commission a report in which the utility specifically answers all questions propounded regarding a major event or events and provides such other information relevant to the major event and the restoration of service as the Commission may request. The Commission may require utilities to provide these supplemental or additional reports at regular intervals, to be determined by the Commission, and on a form approved by the Commission. Periodic or special reports concerning any matter about which the Commission is concerned relative to the occurrence of one or more major events shall be furnished in a manner determined by the Commission and on a form approved by the Commission.

3254. – 3299. [Reserved].

METERS

3300. Service Meters and Related Equipment.

(a) All electric meters used in connection with electric metered service for billing purposes and meters for on-site generation systems shall be furnished, installed, and maintained by the utility.

(b) All equipment, devices, or facilities (including, without limitation, service meters) furnished by the utility and which the utility maintains and renews shall remain the property of the utility and may be removed by it at any time after discontinuance of service.

(c) Each electric service meter shall indicate clearly the kWh and units of demand, where applicable, for which the customer is charged. In cases in which the register and/or chart reading must be multiplied by a constant or factor to obtain the units consumed, the factor, factors, or constant shall be clearly marked either on the register or face of the meter or in permanently attached and clearly visible documentation at the meter location. In cases in which the metering installation is of such a complex nature that disclosure of the constant or factor used is unsuitable to inform the customer of quantities of utility service being consumed, the utility shall attach at the meter location instructions on how the customer can receive such information from the utility.

3301. Location of Service Meters.

(a) As of the time of installation, meters shall be located in accordance with the pertinent utility tariffs and in accordance with accepted safe practice and electric utility industry standards.

(b) As of the time of installation, meters shall be located so as to be easily accessible for reading, testing, and servicing in accordance with accepted safe practice and in accordance with electric utility industry standards.

3302. Service Meter Accuracy.

(a) No service watt-hour meter that has an incorrect register constant, test constant, gear ratio or dial train, or that has a moving element that makes one complete revolution in ten minutes or less with all load wires disconnected, shall be placed in service or allowed to remain in service without proper adjustment and correction.

(b) No service watt-hour meter that has an error in registration of more than plus or minus two percent, either at light load or at heavy load, shall be placed in service. Whenever a meter is found to exceed these limits, it shall be adjusted or replaced.

(c) No demand meter shall have an allowable error of more than two percent of full-scale deflection, except that the allowable error for thermal type meters may be three percent. Whenever a demand meter is found to exceed these limits, it shall be adjusted or replaced.

(d) Meters used with instrument transformers or current transformers shall be adjusted or replaced so that the overall accuracy of the metering installation meets the requirements of this rule.

3303. Meter Testing Equipment and Facilities.

(a) Unless specifically exempted by the Commission, each utility furnishing metered electric service shall provide such meter laboratory, standard meters, instruments, and other equipment and facilities as may be necessary to make the tests required by these rules. Such equipment and facilities shall be acceptable to the Commission and shall be available at all reasonable times for inspection by the Commission's authorized representatives.

(b) Each utility shall make such tests as are prescribed under these rules with such frequency, in such manner, and at such places as may be approved by this Commission. Each utility shall file an application for approval of its testing practices. The application shall include:

(I) all information required by paragraphs 3002(b) and 3002(c);

(II) a description of the test methods employed and the frequency of tests or observations for determining voltage of electric service furnished;

(III) a description of meter testing equipment, including methods employed to ascertain and maintain accuracy of all testing equipment;

(IV) rules covering testing and adjustment of service meters when installed and periodic tests after installation; and

(V) supporting information and justification for the items listed in subparagraphs (II) through (IV) of this paragraph.

(c) Revisions to any portion of testing practices approved pursuant to the procedure in paragraph (b) of this rule shall be accomplished by the filing and approval of a new application.

(d) Each utility furnishing metered electric service shall provide such portable indicating electrical testing instruments or portable watt-hour meters of suitable range and type for testing switchboard instruments, recording volt-meters, service watt-hour meters, and other electrical instruments in use, as may be deemed necessary and satisfactory by the Commission.

(e) Rotating standards that are used by the utility in testing service meters shall be tested for accuracy by using reference standards. If the reference standards used by the utility are service type watt-hour meters, those watt-hour meters must be permanently mounted in the utility's laboratory and may be used for no other purpose than testing rotating standards.

(f) Reference standards shall be submitted at least once each year to a laboratory of recognized standing, for the purpose of testing and adjustment. A utility that maintains its own standardizing laboratory shall be permitted to test and certify its own reference standards, provided the instruments and methods used are acceptable to the Commission.

(g) When in use, commutator-type rotating standards shall be compared with the reference standards in accordance with the manufacturer’s recommended frequency. When in use, induction-type rotating standards shall be compared with the reference standards in accordance with the manufacturer’s recommended frequency. If any working rotating standard tests within plus or minus one percent error at any load at which the standard will be used, the standard may be adjusted by comparison with the utility's reference standards. However, if any working rotating standard tests in error of more than plus or minus one percent, that standard shall be tested, adjusted, and certified in a standardizing laboratory of recognized standing. If a utility is exempted as provided in paragraph (a) of this rule, it shall have its working rotating standards tested by a standardizing laboratory of recognized standing at least once a year. Each rotating standard shall at all times be accompanied by a certificate or calibrating card signed by the standardizing laboratory, giving the date when it was last certified and adjusted.

(h) When in use, all electrical meter testing equipment shall have their calibration checked either annually or more frequently if specified by the manufacturer. For all instruments requiring an as found/as left date sheet, calibration certifications shall be kept on-site for a period of seven years or until the instruments are recertified by a laboratory of recognized standing, whichever is later. All instruments shall have a tag affixed stating the date calibrated and the date the instrument is due for recertification. If an instrument is found to be out of the manufacturer’s specifications, the instrument shall be calibrated and certified to the manufacturer’s specifications by a laboratory of recognized standing. Upon request from any person, a copy of the certification letter and date sheet shall be provided for the instrument in question.

(i) A utility shall keep records of certification and calibrations for all testing equipment required by this rule for the life of the equipment.

(j) In its tariff, a utility shall include a description of its meter testing equipment and of the methods employed to ascertain and to maintain accuracy of all testing equipment.

(k) For those paragraphs of this rule which require a utility to maintain facilities and equipment, a utility may meet those requirements by having the facilities and equipment readily available (as, for example and without limitation, by contracting with a testing facility). A utility which uses this paragraph of the rule is responsible for its compliance with the provisions of this entire rule.

(l) For those paragraphs of this rule which require a utility to test or to maintain equipment, a utility may meet those requirements by having the equipment tested by a third party (as, for example and without limitation, an independent testing facility). A utility which uses this paragraph of the rule is responsible for its compliance with the provisions of this entire rule.

3304. Scheduled Meter Testing.

(a) A utility shall test, or shall arrange for testing of, service meters in accordance with the schedule in this rule or in accordance with a sampling program approved by the Commission.

(b) If it wishes to use a sampling program, a utility shall file an application to request approval of a sampling program. The application shall include:

(I) the information required by paragraphs 3002(b) and 3002(c).

(II) a description of the sampling program which the utility wishes to use. This description shall include, at a minimum the following:

(A) the type(s) of meters subject to the sampling plan;

(B) the frequency of testing;

(C) the procedures to be used for the sampling;

(D) the reference standard to be used for testing; and

(E) the accuracy of the testing and of the sampling plan.

(III) An explanation of the reason(s) for the requested sampling program; and

(IV) an analysis which demonstrates that, with respect to assuring the accuracy of the service meters tested, the requested sampling program is at least as effective as the schedule in this rule.

(c) Revisions to any portion of a sampling program approved pursuant to paragraph (b) of this rule shall be accomplished by the filing of, and Commission approval of, a new application.

(d) Every service meter must be tested and adjusted, either before installation or no later than 60 days after installation, to ensure that it registers accurately and conforms to the requirements of rule 3302. In addition, every service meter shall be tested on a periodic basis, as follows.

(I) Alternating current watt-hour meters.

(A) Polyphase meters used with instrument transformers, every four years.

(B) Single-phase meters used with instrument transformers, every eight years.

(C) Self-contained polyphase meters, every six years.

(D) Self-contained single-phase meters and three wire network meters, every eight years.

(II) Direct current watt-hour meters.

(A) Up to and including 6 KW, every 42 months.

(B) Over 6 KW up to and including 100 KW, every 18 months.

(C) Over 100 KW, every 12 months.

(III) Var-hour meters and lagged demand meters shall be tested on the same schedule as the associated watt-hour meters in subparagraph (c)(I) or (II) of this rule. Integrated (block interval) demand meters, including demand registers and associated control devices, shall be tested on the same schedule as the associated watt-hour meters in subparagraph (c)(I) or (II) of this rule, but at least every six years.

(e) Each utility shall include in its tariff a description of the utility's practices concerning:

(I) testing and adjustment of service meters at installation; and

(II) periodic testing after installation.

3305. Meter Testing Upon Request.

(a) If a customer disputes the accuracy of meter or disputes the billing that implicates the accuracy of a meter, the utility furnishing metered electric service shall inform the customer of his rights to have the meter tested as specified in this rule. Within 30 days of a customer's request, the utility shall remove the meter and test the meter's accuracy using standardized testing equipment (commonly referred to as a "shop test") or test the meter's accuracy using standardized testing equipment in the field (commonly referred to as a "field test"). The test shall be conducted free of charge if the meter has not been tested within the previous 12 months; otherwise, the utility may charge a fee for performing the test. The utility shall provide a written report of the test results to the customer and shall maintain the report on file for at least two years. If, upon completion of the shop or field test, the disputed meter is found to be inaccurate beyond the limits prescribed in rule 3302, it shall be deemed out of compliance.

(b) Should a customer request and receive a meter test as prescribed in paragraph 3305(a) and continue to dispute the accuracy of the meter or the billing that implicates the accuracy of the meter, the utility shall inform the customer of his right to request independent testing of the meter. Upon the customer's request, the utility shall make the disputed meter available for independent testing by a qualified meter testing facility of the customer's choosing. The customer is not entitled to take physical possession of the disputed meter. To be a qualified meter testing facility, the testing facility must be capable of testing the meter to meet all meter standards and requirements required by these rules.

(c) If, upon completion of an independent test as prescribed in paragraph 3305(b), the disputed meter is found to be accurate within the limits of rule 3302, the customer shall bear all costs associated with conducting the test. If, upon completion of an independent test as prescribed in paragraph 3305(b), the disputed meter is found to be inaccurate beyond the limits prescribed in rule 3302, the meter shall be deemed out of compliance and the utility shall bear all costs associated with conducting the test.

(d) Each utility shall identify in its tariff the rates, terms, and conditions for all fees associated with customer-requested meter testing conducted within 12 months of a prior test.

(e) If a meter is deemed out of compliance under this rule, the utility shall inform the customer of his right to request a refund pursuant to rule 3402.

3306. Records of Tests and Meters.

(a) For each meter owned or used by it, a utility shall maintain a record showing the date of purchase, the manufacturer's serial number, the record of the present location, and the date and results of the last test performed by the utility. This record shall be retained for the life of the meter plus 30 months.

(b) Whenever a meter is tested either on request or upon complaint, the test record shall include the information necessary for identifying the meter, the reason for making the test, the reading of the meter if removed from service, the result of the test, and all data taken at the time of the test in a sufficiently complete form to permit the convenient checking of the method employed and the calculations made. This record shall be retained for at least two years.

3307. - 3308. [Reserved].

3309. Meter Reading.

(a) Upon a customer's request, a utility shall provide written documentation showing the date of the most recent reading of the customer’s meter and the total usage expressed in kWh or other unit of service recorded. On request, a utility supplying metered service shall explain to its customers its method of reading meters.

(b) Each utility shall include in its tariff a clear statement describing when meters will be read by the utility and the circumstances, if any, under which the customer must read the meter and submit the data to the utility. This statement shall specify in detail the procedure that the customer must follow and shall specify any special conditions which apply only to certain classes of service.

(c) Absent good cause, a utility shall read a meter monthly. For good cause shown, a utility shall read a meter at least once every six months.

3310. – 3399. [Reserved].

BILLING AND SERVICE

3400. Applicability.

Rules 3400 through 3413 apply to residential customers, small commercial customers and agricultural customers served pursuant to a utility’s rates or tariffs. In its tariffs, a utility shall define “residential,” “small commercial” and “agricultural” customers to which these rules apply. The utility may elect to apply the same or different terms and conditions of service to other customers.

3401. Billing Information and Procedures.

(a) All bills issued to customers for metered service furnished shall show:

(I) the dates and meter readings beginning and ending the period during which service was rendered;

(II) an appropriate rate or rate code identification;

(III) the net amount due for regulated charges;

(IV) the date by which payment is due, which shall not be earlier than 15 days after the mailing or the hand-delivery of the bill;

(V) a distinct marking to identify an estimated bill;

(VI) the total amount of all payments or other credits made to the customer's account during the billing period;

(VII) any past due amount. Unless otherwise stated in a tariff or Commission rule, an account becomes "past due" on the 31st day following the due date of current charges;

(VIII) the identification of, and amount due for, unregulated charges, if applicable;

(IX) any transferred amount or balance from any account other than the customer's current account; and

(X) all other essential facts upon which the bill is based, including factors and constants, as applicable.

(b) A utility that bills for unregulated services or goods shall allocate partial payments first to regulated charges and then to unregulated charges or non-tariff charges and to the oldest balance due separately within each category.

(c) A utility that transfers to a customer a balance from the account of a person other than that customer shall have in its tariffs the utility's benefit of service transfer policies and criteria. The tariffs shall contain an explanation of the process by which the utility will verify, prior to billing a customer under the benefit of service tariff, that the person to be billed in fact received the benefit of service.

(d) A utility may transfer a prior unpaid debt to a customer's bill if the prior bill was in the name of the customer and the utility has informed the customer of the transferred amount and of the source of the unpaid debt (for example, and without limitation, the address of the premises to which service was provided and the period during which service was provided).

(e) If it is offered in a tariff, upon request from a customer and where it is technically feasible, a utility may have the option to provide electronic billing (e-billing), in lieu of a typed or machine-printed bill, to the requesting customer. If a utility offers the option of e-billing, the following shall apply:

(I) the utility shall obtain the affirmative consent of a customer to accept such a method of billing in lieu of printed bills;

(II) the utility shall not charge a fee for billing through the e-billing option;

(III) the utility shall not charge a fee based on customer payment options that is different from the fee charged for the use of the same customer payment options by customers who receive printed bills; and

(IV) a bill issued electronically shall contain the same disclosures and Commission-required information as those contained in the printed bill provided to other customers.

3402. Adjustments for Meter and Billing Errors.

(a) A utility shall adjust customer charges for electricity incorrectly metered or billed as follows:

(I) When, upon any meter accuracy test, a meter is found to be running slow in excess of error tolerance levels allowed under rule 3302, the utility may charge for one-half of the weighted average error for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed six months. As used in this subparagraph, "weighted average error" means the arithmetic average of the percent error at light load and at heavy load giving the heavy load error a weight of four and the light load error a weight of one.

(II) When, upon any meter accuracy test, a meter is found to be running fast in excess of error tolerance levels allowed under rule 3302, the utility shall refund one-half of the weighted average error for the period dating from the discovery of the meter error back to the previous meter test, with such period not to exceed two years. As used in this subparagraph, "weighted average error" means the arithmetic average of the percent error at light load and at heavy load giving the heavy load error a weight of four and the light load error a weight of one.

(III) When a meter does not register, registers intermittently, or partially registers for any period, the utility may estimate, using the method stated in its tariff, a charge for the electricity used based on amounts metered to the customer over a similar period in previous years. The period for which the utility charges the estimated amount shall not exceed six months.

(IV) In the event of under-billings not provided for in subparagraph (a)(I) or (III) of this rule (such as, but not limited to, an incorrect multiplier, an incorrect register, or a billing error), the utility may charge for the period during which the under-billing occurred, with such period not to exceed six months.

(V) In the event of over-billings not provided for in subparagraph (a)(II) of this rule , the utility shall refund for the period during which the over-billing occurred, with such period not to exceed two years.

(b) The periods set out in paragraph (a) of this rule shall commence on the date on which either the customer notifies the utility or the utility notifies the customer of a meter or billing error or, the customer informs the utility of a billing or metering error dispute or makes an informal complaint to the External Affairs section of the Commission.

(c) In the event of an over-billing, the customer may elect to receive the refund as a credit to future billings or as a one-time payment. If the customer elects a one-time payment, the utility shall make the refund within 30 days. Such over-billings shall not be subject to interest.

(d) In the event of under-billing, the customer may elect to enter into a payment arrangement on the under-billed amount. The payment arrangement shall be equal in length to the length of time during which the under-billing lasted. Such under-billings shall not be subject to interest.

3403. Applications for Service, Customer Deposits, and Third-Party Guarantee Arrangements.

(a) A utility shall process an application for utility service which is made either orally or in writing and shall apply nondiscriminatory criteria with respect to the requirement of a cash deposit prior to commencement of service.

(b) If billing records are available for a customer who has received service from the utility, the utility shall not require that person to make new or additional cash deposits to guarantee payment of current bills unless the records indicate recent or substantial delinquencies. All customers shall be treated without undue discrimination with respect to cash deposit requirements, pursuant to the utility's tariff.

(c) A utility shall not require a cash deposit from an applicant for service who provides written documentation of a 12 consecutive month good credit history from the utility from which that person received similar service. For purposes of this paragraph, the 12 consecutive months must have ended no earlier than 60 days prior to the date of the application for service.

(d) If a utility uses credit scoring to determine whether to require a cash deposit from an applicant for service or a customer, the utility shall have a tariff which describes, for each scoring model that it uses, the credit scoring evaluation criteria and the credit score limit which triggers a cash deposit requirement.

(e) All utilities requiring deposits shall offer customers at least one non-cash alternative that does not require the use of the customer's social security number, in lieu of a cash deposit.

(f) If a utility uses credit scoring, prior payment history with the utility, or customer-provided prior payment history with a like utility as a criterion for establishing the need for a cash deposit, the utility shall include in its tariff the specific evaluation criteria which trigger the need for a cash deposit.

(g) If a utility denies an application for service or requires a cash deposit as a condition of providing service, the utility immediately shall inform the applicant for service of the decision and shall provide, within three business days, a written explanation to the applicant for service stating the reasons the application for service has been denied or a cash deposit is required.

(h) No utility shall require any surety other than either a cash deposit to secure payment for utility services or a third-party guarantee of payment in lieu of a cash deposit. In no event shall the furnishing of utility services or extension of utility facilities, or any indebtedness in connection therewith, result in a lien, mortgage, or other interest in any real or personal property of the customer unless such indebtedness has been reduced to a judgment. Should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a cash deposit or a new third party guarantor.

(i) A cash deposit shall not exceed an amount equal to an estimated 90 days' bill of the customer, except in the case of a customer whose bills are payable in advance of service, in which case the cash deposit shall not exceed an estimated 60 days' bill of the customer. The cash deposit may be in addition to any advance, contribution, or guarantee in connection with construction of lines or facilities, as provided in the extension policy in the utility's tariffs.

(j) A utility receiving cash deposits shall maintain records showing:

(I) the name of each customer making a cash deposit;

(II) the amount and date of the cash deposit;

(III) each transaction, such as the payment of interest or interest credited, concerning the cash deposit;

(IV) each premises where the customer receives service from the utility while the cash deposit is retained by the utility;

(V) if the cash deposit was returned to the customer, the date on which the cash deposit was returned to the customer; and

(VI) if the unclaimed cash deposit was paid to the energy assistance organization, the date on which the cash deposit was paid to the energy assistance organization.

(k) Each utility shall state in its tariff its customer deposit policy for establishing or maintaining service. The tariff shall state the circumstances under which a cash deposit will be required and the circumstances under which it will be returned.

(l) Each utility shall issue a receipt to every customer from whom a cash deposit is received. No utility shall refuse to return a cash deposit or any balance to which a customer may be entitled solely on the basis that the customer is unable to produce a receipt.

(m) The payment of a cash deposit shall not relieve any customer from the obligation to pay current bills as they become due. A utility is not required to apply any cash deposit to any indebtedness of the customer to the utility, except for utility services due or past due after service is terminated.

(n) A utility shall pay simple interest on a cash deposit at the percentage rate per annum as calculated by Commission staff and in the manner provided in this paragraph.

(I) At the request of the customer, the interest shall be paid to the customer either on the return of the cash deposit or annually. The simple interest on a cash deposit shall be earned from the date the cash deposit is received by the utility to the date the customer is paid. At the option of the utility, interest payments may be paid directly to the customer or by a credit to the customer's account.

(II) The simple interest to be paid on a cash deposit during any calendar year shall be at a rate equal to the average for the period October 1 through September 30 (of the immediately preceding year) of the 12 monthly average rates of interest expressed in percent per annum, as quoted for one-year United States Treasury constant maturities, as published in the Federal Reserve Bulletin, by the Board of Governors of the Federal Reserve System. Each year, Commission staff shall compute the interest rate to be paid. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is less than 25 basis points, the existing customer deposit interest rate shall continue for the next calendar year. If the difference between the existing customer deposit interest rate and the newly calculated customer deposit interest rate is 25 basis points or more, the newly calculated customer deposit interest rate shall be used. The Commission shall send a letter to each utility stating the rate of interest to be paid on cash deposits during the next calendar year. Annually following receipt of Commission staff's letter, if necessary, each utility shall file by advice letter or application, as appropriate, a revised tariff, effective the first day of January of the following year, or on an alternative date set by the Commission, containing the new rate of interest to be paid upon customers' cash deposits, except when there is no change in the rate of interest to be paid on such deposits.

(o) A utility shall have tariffs concerning third-party guarantee arrangements and, pursuant to those tariffs, shall offer the option of a third party guarantee arrangement for use in lieu of a cash deposit. The following shall apply to third-party guarantee arrangements:

(I) an applicant for service or a customer may elect to use a third-party guarantor in lieu of paying a cash deposit;

(II) the third-party guarantee form, signed by both the third-party guarantor and the applicant for service or the customer, shall be provided to the utility;

(III) the utility may refuse to accept a third-party guarantee if the guarantor is not a customer in good standing at the time of the guarantee;

(IV) the amount guaranteed shall not exceed the amount which the applicant for service or the customer would have been required to provide as a cash deposit;

(V) the guarantee shall remain in effect until the earlier of the following occurs: it is terminated in writing by the guarantor; if the guarantor was a customer at the time of undertaking the guarantee, the guarantor is no longer a customer of the utility; or the customer has established a satisfactory payment record, as defined in the utility's tariffs, for 12 consecutive months; and

(VI) should the guarantor terminate service or terminate the third party guarantee before the customer has established a satisfactory payment record for 12 consecutive months, the utility, applying the criteria contained in its tariffs, may require a cash deposit or a new third party guarantor.

(p) A utility shall pay all unclaimed monies, as defined in § 40-8.5-103(5), C.R.S., that remain unclaimed for more than two years to the energy assistance organization. “Unclaimed monies” shall not include: undistributed refunds for overcharges subject to other statutory provisions and rules; and, credits to existing customers from cost adjustment mechanisms.

(I) Monies shall be deemed unclaimed and presumed abandoned when left with the utility for more than two years after termination of the services for which the cash deposit or the construction advance was made or when left with the utility for more than two years after the cash deposit or the construction advance becomes payable to the customer pursuant to a final Commission order establishing the terms and conditions for the return of such deposit or advance and the utility has made reasonable efforts to locate the customer.

(II) Interest on a cash deposit shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the utility receives the cash deposit and ending on the date on which the cash deposit is paid to the energy assistance organization. If the utility does not pay the unclaimed cash deposit to the energy assistance organization within four months of the date on which the unclaimed cash deposition is deemed to be unclaimed or abandoned pursuant to subparagraph (o)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed cash deposit at the rate established pursuant to paragraph (n) of this rule plus six percent..

(III) If payable under the utility’s line extension tariff provisions, interest on a construction advance shall accrue at the rate established pursuant to paragraph (n) of this rule commencing on the date on which the construction advance is deemed to be owed to the customer pursuant to the utility’s extension policy and ending on the date on which the construction advance is paid to the energy assistance organization. If the utility does not pay the unclaimed construction advance to the energy assistance organization within four months of the date on which the unclaimed construction advance is deemed to be unclaimed or abandoned pursuant to subparagraph (o)(I) of this rule, then at the conclusion of the four-month period, interest shall accrue on the unclaimed construction advance at the rate established pursuant to paragraph (n) of this rule plus six percent.

(q) A utility shall resolve all inquiries regarding a customer’s unclaimed monies and shall not refer such inquiries to the energy assistance organization.

(r) If a utility has paid unclaimed monies to the energy assistance organization, a customer later makes an inquiry claiming those monies, and the utility resolves the inquiry by paying those monies to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

(s) For purposes of paragraphs (p), (q), and (r) of this rule, “utility” means and includes: a cooperative electric association which elects to be so governed; and, a utility as defined in paragraph 3001(ff).

3404. Installment Payments.

(a) In its tariffs, a utility shall have a budget or level- payment plan available for its customers.

(b) In its tariff, a utility shall have an installment payment plan which permits a customer to make installment payments if one of the following applies.

(I) The plan is to pay regulated charges from past billing periods and the past due amount arises solely from events under the utility’s control (such as, without limitation, meter malfunctions, billing errors, utility meter reading errors, or failures to read the meter, except where the customer refuses to read the meter and it is not readily accessible to the utility). A utility shall advise a customer who is eligible for this type of plan of the customer's eligibility. At the request of the customer and at the customer's discretion, an installment payment plan under this subparagraph shall extend over a period equal in length to that during which the errors were accumulated and shall not include interest.

(II) The customer pays at least ten percent of the amount shown on the notice of discontinuance for regulated charges and enters into an installment payment plan on or before the expiration date of the notice of discontinuance.

(III) The customer pays at least ten percent of any regulated charges amount more than 30 days past due and enters into an installment payment plan on or before the last day covered by a medical certification. A customer who has entered into and failed to abide by an installment payment plan prior to receiving a medical certification shall pay all amounts that were due for regulated charges up to the date on which the customer presented a medical certification which meets the requirements of subparagraph 3407(e)(IV) and then may resume the installment payment plan.

(IV) If service has been disconnected, the customer pays at least any collection and reconnection charges and enters into an installment payment plan. This subparagraph shall not apply if service was discontinued because the customer breached a prior payment arrangement.

(c) Installment payment plans shall include the following amounts that are applicable at the time the customer requests a payment arrangement:

(I) the unpaid remainder of amounts due for regulated charges shown on the notice of discontinuance;

(II) any amounts due for regulated charges not included in the amount shown on the notice of discontinuance which have since become more than 30 days past due;

(III) all current regulated charges contained in any bill which is past due but is less than 30 days past the due date;

(IV) any new regulated charges contained in any bill which has been issued but is not past due;

(V) any regulated charges which the customer has incurred since the issuance of the most recent monthly bill;

(VI) any collection fees as provided for in the utility's tariff, whether or not such fees have appeared on a regular monthly bill;

(VII) any deposit, whether already billed, billed in part, or required by the utility's tariff, due for discontinuance or delinquency or to establish initial credit, other than a cash deposit required as a condition of initiating service; and

(VIII) any other regulated charges or fees provided in the utility's tariff (including without limitation miscellaneous service charges, investigative charges, and checks returned for insufficient funds charges), whether or not they have appeared on a regular monthly bill.

(d) Within seven calendar days of entering into a payment arrangement with a customer, a utility shall provide the customer with a copy of this rule and a statement describing the payment arrangement. The statement describing the payment arrangement shall include the following:

(I) the terms of the payment plan; and

(II) a description of the steps which the utility will take if the customer does not abide by payment plan.

(e) Except as provided in subparagraph (b)(I) of this rule, an installment payment plan shall consist, at a minimum, of equal monthly installments for a term selected by the customer but not to exceed six months. In the alternative, the customer may choose a modified budget billing, level payment, or similar tariff payment arrangement in which the total due shall be added to the preceding year's total billing to the customer's premises, modified for any base rate or cost adjustment changes. The resulting amount shall be divided and billed in 11 equal monthly budget billing payments, followed by a settlement billing in the twelfth month, or shall follow other payment-setting practices consistent with the tariff plan available.

(f) For an installment payment plan entered into pursuant to this rule, the first monthly installment payment, and with the new charges (unless the new charges have been made part of the arrangement amount) shall be due on a date which is not earlier than the next regularly-scheduled due date of the customer who is entering into the installment payment plan. Succeeding installment payments, together with the new charges, shall be due in accordance with the due date established in the installment payment plan. Any payment not made on the due date established in the installment payment plan shall be considered in default. Any new charges that are not paid by the due date shall be considered past due, excluding those circumstances covered in subparagraph (b)(I) of this rule.

(g) This rule shall not be construed to prevent a utility from offering any other installment payment plan terms to avoid discontinuance or terms for restoration of service, provided the terms are at least as favorable to the customer as the terms set out in this rule.

3405. Service, Rate, and Usage Information.

(a) In addition to the requirement found in rule 1206, a utility shall inform its customers of any change proposed or made in any term or condition of its service if that change or proposed change will affect the quality of the service provided.

(b) A utility shall transmit information provided pursuant to this rule through the use of a method (such as, without limitation, bill inserts or periodic direct mail) that will assure receipt by each customer.

(c) Upon request, a utility must provide the following information to a customer:

(I) a clear and concise summary of the existing rate schedule applicable to each major class of customers for which there is a separate rate;

(II) an identification of each class whose rates are not summarized;

(III) a clear and concise explanation of the existing rate schedule applicable to the customer. This shall be provided within ten days of a customer's request or, in the case of a new customer, within 60 days of the commencement of service;

(IV) a clear and concise statement of the customer's actual consumption or degree-day adjusted consumption of electricity for each billing period during the prior year, unless such consumption data are not reasonably ascertainable by the utility; and

(V) any other information and assistance as may be reasonably necessary to enable the customer to secure safe and efficient service.

3406. Component and Source Disclosures.

(a) Each utility shall provide, by a bill insert or a separate mailing, the following itemized information to its customers in April and October of each year:

(I) The percentage components, which include fixed and variable components, of the total average delivered price of electricity, residential or commercial, as applicable, attributable both to power supply and to power delivery for the previous calendar year. As used in this rule, "power supply" includes all generation, purchase power, and non-utility transmission components. As used in this rule, "power delivery" includes all utility transmission and distribution components.

(II) The power supply mix, which lists the fuel sources, expressed as a percentage of average annual power acquired and generated by the utility for the previous calendar year. The utility shall make reasonable efforts to identify and to include, to the extent that they are identifiable, all power supplied by non-utility generation sources in the power supply fuel source composition. Those sources which are not identifiable shall be listed as "imported, fuel source unknown." Fuel mixture information must use the following fuel type categories in the following order, rounded to the nearest tenth of one percent: biomass and waste; coal; geothermal; hydroelectric; natural gas; nuclear; solar; wind; and imported, fuel source unknown.

(b) Price components and sources of power supply shall appear together in a format no larger than one page and shall be clearly legible, as follows:

ELECTRICITY FACTS		
Price Components Percentage components for an average monthly residential* electric bill.		Residential * Service
	Power Supply (Generation & Purchase)	xx%
	Power Delivery (Transmission & Distribution)	xx%
Power Supply Mix (Generation & Purchase) Fuel sources used in power generation and purchase for the calendar year xxxx for all utility customers.	Fuel Type	%
	Bio-mass and Waste	x.x%
	Coal	x.x%
	Geothermal	x.x%
	Hydroelectric	x.x%
	Natural Gas	x.x%
	Nuclear	x.x%
	Solar	x.x%
	Wind	x.x%
	Imported, Fuel Source Unknown	x.x%
	Total	100%

3407. Discontinuance of Service.

(a) A utility shall not discontinue the service of a customer for any reason other than the following:

(I) nonpayment of regulated charges;

(II) fraud or subterfuge;

(III) service diversion;

(IV) equipment tampering;

(V) safety concerns;

(VI) exigent circumstances;

(VII) discontinuance ordered by any appropriate governmental authority; or

(VIII) properly discontinued service being restored by someone other than the utility when the original cause for proper discontinuance has not been cured.

(b) A utility shall not discontinue service for nonpayment of any of the following.

(I) Any amount which has not appeared on a regular monthly bill or which is not past due. Unless otherwise stated in a tariff or Commission rule, an account becomes “past due” on the 31st day following the due date of current charges.

(II) Any amount due on another account now or previously held or guaranteed by the customer, or with respect to which the customer received service, unless the amount has first been transferred either to an account which is for the same class of service or to an account which the customer has agreed will secure the other account. Any amount so transferred shall be considered due on the regular due date of the bill on which it first appears and shall be subject to notice of discontinuance as if it had been billed for the first time.

(III) Any amount due on an account on which the customer is or was neither the customer of record nor a guarantor, or any amount due from a previous occupant of the premises. This subparagraph does not apply if the customer is or was obtaining service through fraud or subterfuge or if paragraph 3401(c) applies.

(IV) Any amount due on any account for which the present customer is or was the customer of record, if another person established the account through fraud or subterfuge and without the customer's knowledge or consent.

(V) Any delinquent amount, unless the utility can supply billing records from the time the delinquency occurred.

(VI) Any debt except that incurred for service rendered by the utility in Colorado.

(VII) Any unregulated charge.

(c) If the utility discovers any connection or device installed on the customer's premises, including any energy-consuming device connected on the line side of the utility's meter, which would prevent the meter from registering the actual amount of energy used, the utility shall do one of the following.

(I) Remove or correct such devices or connections. If the utility takes this action, it shall leave at the premises a written notice which advises the customer of the violation, of the steps taken by the utility to correct it, and of the utility's ability to bill the customer for any estimated energy consumption not properly registered. This notice shall be left at the time the removal or correction occurs.

(II) Provide the customer with written notice that the device or connection must be removed or corrected within 15 days and that the customer may be billed for any estimated energy consumption not properly registered. If the utility elects to take this action and the device or connection is not removed or corrected within the 15 days permitted, then within seven calendar days from the expiration of the 15 days, the utility shall remove or correct the device or connection pursuant to subparagraph (c)(I) of this rule.

(d) If a utility discovers evidence that any utility-owned equipment has been tampered with or that service has been diverted, the utility shall provide the customer with written notice of the discovery. The written notice shall inform the customer of the steps the utility will take to determine whether non-registration of energy consumption has or will occur and shall inform the customer that the customer may be billed for any estimated energy consumption not properly registered. The utility shall mail or hand-deliver the written notice within three calendar days of making the discovery of tampering or service diversion.

(e) A utility shall not discontinue service, other than to address safety concerns or in exigent circumstances, if one of the following is met.

(I) If a customer at any time tenders full payment in accordance with the terms and conditions of the notice of discontinuance to a utility employee authorized to receive payment, including any employee dispatched to discontinue service. Payment of a charge for a service call shall not be required to avoid discontinuance.

(II) If a customer pays, on or before the expiration date of the notice of discontinuance, at least one-tenth of the amount shown on the notice and enters into an installment payment plan with the utility, as provided in rule 3404.

(III) If it is between 12 Noon on Friday and 8 a.m. the following Monday; between 12 Noon on the day prior to and 8:00 a.m. on the day following any state or federal holiday; or between 12 Noon on the day prior to and 8:00 a.m. on the day following any day during which the utility's local office is not open.

(IV) Medical emergencies.

(A) A utility shall postpone discontinuance of electric service to a residential customer for 90 days from the date of a medical certificate issued by a Colorado-licensed physician or health care practitioner acting under a physician's authority which evidences that discontinuance of service will aggravate an existing medical emergency or create a medical emergency for the customer or a permanent resident of the customer's household. A customer may invoke this subparagraph 3407(e)(IV)(A) only once in any twelve consecutive months.

(B) As a condition of obtaining a new installment payment plan on or before the last day covered by a medical certificate, a customer who had already entered into a payment arrangement, but had broken the arrangement prior to seeking a medical certification, may be required to pay all amounts that were due up to the date of the original medical certificate as a condition of obtaining a new payment arrangement. At no time shall a payment from the customer be required as a condition of honoring a medical certificate.

(C) The certificate of medical emergency shall be in writing, sent to the utility from the office of a licensed physician, and show clearly the name of the customer or individual whose illness is at issue; the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the medical emergency. Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

3408. Notice of Discontinuance of Service.

(a) Except as provided in paragraphs (g) and (h) of this rule, a utility shall provide, by first class mail or by hand-delivery, written notice of discontinuance of service at least 15 days in advance of any proposed discontinuance of service. The notice shall be conspicuous and in easily understood language, and the heading shall contain, in capital letters, the following warning:

THIS IS A FINAL NOTICE OF DISCONTINUANCE OF UTILITY SERVICE AND CONTAINS IMPORTANT INFORMATION ABOUT YOUR LEGAL RIGHTS AND REMEDIES. YOU MUST ACT PROMPTLY TO AVOID UTILITY SHUT OFF.

(b) The body of the notice of discontinuance under paragraph (a) of this rule shall advise the customer of the following.

(I) The reason for the discontinuance of service and of the particular rule (if any) which has been violated.

(II) The amount past due for utility service, deposits, or other regulated charges, if any.

(III) The date by which an installment payment plan must be entered into or full payment must be received in order to avoid discontinuance of service.

(IV) How and where the customer can pay or enter into an installment payment plan prior to the discontinuance of service.

(V) That the customer may avoid discontinuance of service by entering into an installment payment plan with the utility pursuant to rule 3404 and the utility's applicable tariff.

(VI) That the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.

(VII) That the customer has the right to dispute the discontinuance directly with the utility by contacting the utility, and how to contact the utility toll-free from within the utility's service area.

(VIII) That the customer has the right to make an informal complaint to the External Affairs section of the Commission in writing, by telephone, or in person, along with the Commission's address and local and toll-free telephone number.

(IX) That the customer has the right to file a formal complaint, in writing, with the Commission pursuant to rule 1302 and that this formal complaint process may involve a formal hearing.

(X) That in conjunction with the filing of a formal complaint, the customer has a right to file a motion for a Commission order ordering the utility not to disconnect service pending the outcome of the formal complaint process and that the Commission may grant the motion upon such terms as it deems reasonable, including but not limited to the posting of a cash deposit or bond with the utility or timely payment of all undisputed regulated charges.

(XI) That if service is discontinued for non-payment, the customer may be required, as a condition of restoring service, to pay reconnection and collection charges in accordance with the utility's tariff.

(XII) That qualified low-income customers may be able to obtain financial assistance to assist with the payment of the utility bill and that more detailed information on that assistance may be obtained by calling the utility toll-free. The utility shall state its toll-free telephone number.

(c) At the time it provides notice of discontinuance to the customer, a utility shall also provide written notice by first class mail or hand-delivery to any third-party the customer has designated in writing to receive notices of discontinuance or broken arrangement.

(d) A discontinuance notice shall be printed in English and a specific language or languages other than English where the utility's service territory contains a population of at least ten percent who speak a specific language other than English as their primary language as determined by the latest U.S. Census information.

(e) A utility shall explain and shall offer the terms of an installment payment plan to each customer who contacts the utility in response to a notice of discontinuance of service.

(f) Following the issuance of the notice of discontinuance of service, and at least 24 hours prior to discontinuance of service, a utility shall attempt to give notice of the proposed discontinuance in person or by telephone both to the customer and to any third party the customer has designated in writing to receive such notices. If the utility attempts to notify the customer in person but fails to do so, it shall leave written notice of the attempted contact and its purpose.

(g) If a customer has entered into an installment payment plan and has defaulted or allowed a new bill to remain unpaid past its due date, a utility shall provide, by first class mail or by hand-delivery, a written notice to the customer. The notice shall contain:

(I) a heading as follows: NOTICE OF BROKEN ARRANGEMENT;

(II) statements that advise the customer:

(A) that the utility may discontinue service if it does not receive the monthly installment payment within ten days after the notice is mailed or hand-delivered;

(B) that the utility may discontinue service if it does not receive payment for the current bill within 30 days after its due date;

(C) that, if service is discontinued, the utility may refuse to restore service until the customer pays all amounts for regulated service more than 30 days past due and any collection or reconnection charges; and

(D) that the customer has certain rights if the customer or a member of the customer's household is seriously ill or has a medical emergency.

(h) A utility is not required to provide notice under this rule if one of the following applies:

(I) the situation involves safety concerns or exigent circumstances;

(II) discontinuance is ordered by any appropriate governmental authority;

(III) either paragraph 3407(c) or 3407(d) applies; or

(IV) service, having been already properly discontinued, has been restored by someone other than the utility and the original cause for discontinuance has not been cured.

(i) Where a utility knows that the service to be discontinued is used by customers in multi-unit dwellings, in places of business, or in a cluster of dwellings or places of business and the utility service is recorded on a single meter used either directly or indirectly by more than one unit, the utility shall issue notice as required in paragraphs (a) and (b) of this rule, except that:

(I) the notice period shall be 30 days;

(II) such notice may include the current bill;

(III) the utility shall provide written notice to each individual unit, stating that a notice of discontinuance has been sent to the party responsible for the payment of utility bills for the unit and that the occupants of the units may avoid discontinuance by paying the next new bill in full within 30 days of its issuance and successive new bills within 30 days of issuance; and

(IV) the utility shall post the notice in at least one of the common areas of the affected location.

3409. Restoration of Service.

(a) Unless prevented from doing so by safety concerns or exigent circumstances, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 3407, 3408, and 3409.

(b) Unless prevented by safety concerns or exigent circumstances, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:

(I) pays in full the amount for regulated charges shown on the notice and any deposit and/or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;

(II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;

(III) presents a medical certification, as provided in subparagraph 3407(e)(IV); or

(IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

3410. Refunds.

(a) If it seeks to refund monies, a utility shall file an application for Commission approval of a refund plan.

(b) The application for approval of a refund plan shall include, in the following order and specifically identified, the following information either in the application or in the appropriately identified attachments:

(I) all the information required in paragraphs 3002(b) and 3002(c);

(II) the reason for the proposed refund;

(III) a detailed description of the proposed refund plan, including the type of utility service involved, the service area involved, the class(es) of customers to which the refund will be made, and the dollar amount (both the total amount and the amount to be paid to each customer class) of the proposed refund. The interest rate on the refund shall be the current interest rate in the applying utility's customer deposits tariff;

(IV) the date the applying utility proposes to start making the refund, which shall be no more than 60 days after the filing of the application; the date by which the refund will be completed; and the means by which the refund is proposed to be made;

(V) if applicable, a reference (by proceeding number, decision number, and date) to any Commission decision requiring the refund or, the order itself if the refund is to be made because of receipt of monies by the applying utility under the order of a court or of another state or federal agency;

(VI) a statement describing in detail the extent to which the applying utility has any financial interest in any other company involved in the refund plan;

(VII) a statement showing accounting entries under the Uniform System of Accounts; and

(VIII) a statement that, if the application is granted, the applying utility will file an affidavit establishing that the refund has been made in accordance with the Commission's decision.

(c) A utility shall pay 90 percent of all undistributed balances, plus associated interest, to the energy assistance organization. For purposes of this rule, a refund is deemed undistributed if, after good faith efforts, a utility is unable to find the person entitled to a refund within the period of time fixed by the Commission in its decision approving the refund plan.

(d) A utility shall pay an undistributed refund to the energy assistance organization within four months after the refund is deemed undistributed. A utility shall pay interest on an undistributed refund from the time it receives the refund until the refund is paid to the energy assistance organization. The interest rate shall be equal to the interest rate set by the Commission pursuant to paragraph 3403(m).

(e) Whenever a utility makes a refund, it shall provide written notice to those customers that it believes may be master meter operators. The notice shall contain:

(I) the definition of master meter operator, as set forth in these rules;

(II) a statement regarding a master meter operator's obligation to do the following:

(A) to notify its end users of their right to claim, within 90 days, their proportionate share of the refund; and

(B) after 90 days, if the unclaimed balance exceeds $100, to remit the unclaimed balance to the energy assistance organization.

(f) A utility shall resolve all inquiries regarding a customer's undistributed refund and shall not refer such inquiries to the energy assistance organization.

(g) If a utility has paid an undistributed refund to the energy assistance organization, a customer later makes an inquiry claiming that refund, and the utility resolves the inquiry by paying that refund to the customer, the utility may deduct the amount paid to the customer from future funds submitted to the energy assistance organization.

(h) For purposes of paragraphs (c), (d), (e), (f), and (g) of this rule, "utility" means and includes: a cooperative electric association which elects to be so governed; and, a utility as defined in paragraph 4001(ff).

3411. Low-Income Energy Assistance Act.

(a) Scope and applicability.

(I) Rule 3411 is applicable to electric utilities, combined gas and electric utilities, and cooperative electric association except those exempted under (II) or (III). Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.

(II) Municipally owned electric utilities, combined gas and electric utilities, or cooperative electric associations are exempt if:

(A) the utility operates an alternative energy assistance program to support its low-income customers with their energy needs and self-certifies to the organization through written statement that its program meets the following criteria:

(i) the amount and method for funding of the program has been determined by the governing body; and

(ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals; or

(B) the governing body of the utility determines its service area has a limited number of people who qualify for energy assistance and self-certifies to the organization via written statement such determination.

(III) A municipally owned electric utility, combined gas and electric utility, or cooperative electric association not exempt under subparagraph (II), is exempt if:

(A) the utility designs and implements a procedure to notify all customers at least twice each year of the option to conveniently contribute to the organization by means of a monthly energy assistance charge. Such procedure shall be approved by the governing utility. The governing body of such utility shall determine the disposition and delivery of the optional energy assistance charge that it collects on the following basis:

(i) delivering the collections to the organization for distribution; or

(ii) distributing the moneys under criteria developed by the governing body for the purpose set forth in subparagraph (II)(A)(ii).

(B) Alternatively, the utility provides funding for energy assistance to the organization by using a source of funding other than the optional customer contribution on each customer bill that approximates the amount reasonably expected to be collected from an optional charge on customer's bills.

(IV) A municipally owned electric utility, combined gas and electric utility, or cooperative electric association that is exempt under subparagraph (III) shall be entitled to participate in the organization's low-income assistance program.

(V) Electric utilities, combined gas and electric utilities, and cooperative electric associations that desire a change in status must inform the organization and file a notice to the Commission within 30 days prior to expected changes.

(b) Definitions. The following definitions apply only in the context of rule 3411. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply:

(I) "Alternative energy assistance program" means a program operated by a municipally owned electric and gas utility or rural electric cooperative that is not part of the energy assistance program established pursuant to this statute.

(II) "Customer" means the named holder of an individually metered account upon which charges for electricity or gas are paid to a utility. "Customer" shall not include a customer that receives electricity or gas for the sole purpose of reselling the electricity or gas to others.

(III) "Energy assistance program" or "Program" means the Low Income Energy Assistance Program created by § 40-8.7-104, C.R.S., and designed to provide financial assistance, residential energy efficiency, and energy conservation assistance.

(IV) "Organization" means Energy Outreach Colorado, a Colorado nonprofit corporation, formerly known as the Colorado Energy Assistance Foundation.

(V) "Remittance device" means the section of a customer's utility bill statement that is returned to the utility company for payment. This includes but is not limited to paper payment stubs, web page files used to electronically collect payments, and electronic fund transfers.

(VI) "Utility" means a corporation, association, partnership, cooperative electric association, or municipally owned entity that provides retail electric service or retail gas service to customers in Colorado. "Utility" does not mean a propane company.

(c) Plan implementation and maintenance.

(I) Except as provided in paragraph 3411(a), each utility shall implement and maintain a customer opt-in contribution mechanism. The utility's opt-in mechanism shall include, at minimum, the following provisions:

(A) A description of the procedures the utility will use to notify its customers, including those customers that make payments electronically, about the opt-in provision prior to September 1, 2006. Utilities may combine their efforts to notify customers into a single state-wide or region-wide effort consistent with the participating utilities communication programs. Each participating utility shall clearly identify its support of the combined communications program, with its corporate name and/or logo visible to the intended audience.

(B) A description of the additional efforts the utility will use to inform its customers about the program to ensure that adequate notice of the opt-in provision is given to all customers. Notification shall include communication to all customers that the donation and related information will be passed through to the Organization.

(C) A description of the check-off mechanism that will be displayed on the monthly remittance device to solicit voluntary donations. The remittance device shall include, at minimum, check-off categories of five dollars, ten dollars, twenty dollars, and "other amount". The remittance device must also note the name of the program as the "voluntary energy assistance program," or if the utility is unable to identify the name of the program individually, the utility shall use a general energy assistance identifier approved by the Commission.

(D) A description or an example of how the utility will display the voluntary contribution as a separate line item on the customer's monthly billing statement and how the voluntary contribution will be included in the total amount due. The line item must identify the contribution as "voluntary".

(E) A description of the notification process that the utility will use to ensure that once a utility customer opts into the program, the energy assistance contribution will be assessed on a monthly basis until the customer notifies the utility of the customer's desire to stop contributing. The utility shall describe how it will manage participation in the program when customers miss one or more voluntary payment, or pay less than the pre-selected donation amount.

(F) Identification of the procedures the utility will use to notify customers of their ability to cancel or discontinue voluntary contributions along with a description of the mechanism the utility will use to allow customers who make electronic payments to discontinue their participation in the opt-in program.

(G) A description of the procedures the utility will use, where feasible, to notify customers participating in the program about the customer's ability to continue to contribute when the customer changes their address within the utility's service territory.

(H) A description of the method the utility will use to provide clear, periodic, and cost-effective notice of the opt-in provision to its customers at least twice per year. Acceptable methods include, but are not limited to, bill inserts, statements on the bill or envelope, and other utility communication pieces.

(I) An estimate of the start-up costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate should include the utility's initial costs of setting up the collection mechanism and reformatting its billing systems to solicit the optional contribution but shall not include the cost of any notification efforts by the utility. Utilities may elect to recover all start-up costs before the remaining moneys generated by the program are distributed to the Organization or over a period of time from the funds generated by the program, subject to Commission review and approval.

(J) An estimate of the on-going costs that the utility expects to incur in connection with the program along with supporting detailed justification for such costs. This estimate shall not include the cost of any notification efforts by the utility.

(K) A detailed justification for the costs identified in (I) and (J). As stated in § 40-8.7-104(3), C.R.S., the costs incurred must be reasonable in connection with the program.

(L) Utilities shall recover the startup cost and on-going cost of administration associated with the program from funds generated from the program. Insert and notification costs shall be considered in the utility's cost of service.

(M) A description of the procedures the utility will use to account for and process program donations separately from customer payments for utility services.

(II) Each utility shall participate in the energy assistance program consistent with its plan approved by the Commission and shall provide the opportunity for its customers to make an optional energy assistance contribution on the monthly remittance device on their utility billing.

(III) The utility may submit an application to the Commission no later than April 1 of each year for approval of reimbursement costs the utility incurred for the program during the previous calendar year. Such application shall include a proposed schedule for the reimbursement of these costs to the utility. The applications shall include detailed supporting justification for approval of these costs. Such detailed justification includes, but is not limited to, copies of receipts and time sheets. Such applications shall not seek reimbursement of costs related to notification efforts. Participating utilities may include reimbursement costs for such notification efforts in their periodic cost of service rate filings, subject to Commission review and approval.

(IV) A utility may seek modification of its initial plan or subsequent plans by filing an application with the Commission. Such application shall meet the requirements of (d)(I).

(d) Fund administration.

(I) At a minimum, each utility shall transfer the funds collected from its customers under the Energy assistance program to the organization under the following schedule:

(A) for the funds collected during the period of January 1 to March 31 of each year, the utility shall transfer the collected funds to the organization before May 1 of such year;

(B) for the funds collected during the period of April 1 to June 30 of each year, the utility shall transfer the collected funds to the organization before August 1 of such year;

(C) for the funds collected during the period of July 1 to September 30 of each year, the utility shall transfer the collected funds to the organization before November 1 of such year;

(D) for the funds collected during the period of October 1 to December 31 of each year, the utility shall transfer the collected funds to the organization before February 1 of the next year; and

(E) each utility shall maintain a separate accounting for all energy assistance program funds received by customers.

(II) Each utility shall provide the organization with the following information.

(A) How the funds collected for the previous calendar year were generated, including the number of customers participating in the program. Such report shall include a summary of the number of program participants and funds collected by month, and shall be provided by February 1 of each year.

(B) At each time funds are remitted, a listing of all program participants including the donor’s name, billing address, and monthly donation amount. The participant information provided to the organization shall be used exclusively for complying with the requirements of § 40-8.7-101, C.R.S., et seq. and state and federal laws.

(III) The Commission shall submit, as necessary, a bill for payment to the organization for any administrative costs incurred pursuant to the program.

(IV) The organization shall provide the Office of Consumer Counsel and the Commission with a copy of the written report that is described in § 40-8.7-110, C.R.S. This report shall not contain individual participant information.

(e) Prohibition of disconnection. Utilities shall not disconnect a customer's electric service for non-payment of optional contribution amounts.

3412. Electric Service Low-Income Program.

Electric Service Low-Income Program.

(a) Scope and applicability.

(I) Electric utilities with Colorado retail customers shall provide low-income energy assistance by offering rates, charges, and services that grant a reasonable preference or advantage to residential low-income customers, as permitted by § 40-3-106, C.R.S.

(II) Rule 3412 is applicable to investor-owned electric utilities subject to rate regulation by the Commission.

(b) Definitions. The following definitions apply only in the context of rule 3412. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(I) "Administrative cost" means the utility's direct cost for labor (to include the cost of benefit loadings), materials, and other verifiable expenditures directly related to the administration and operation of the program not to exceed ten percent of the total cost of program credits applied against bills for current usage and pre-existing arrearages or $10,000, whichever amount is greater.

(II) "Affordable percentage of income payment" means the amount of the participant's annual bill deemed affordable under subparagraph 3412(e)(I).

(III) "Arrearage" means the past-due amount appearing, as of the date on which a participant newly enters the program, on the then most recent prior bill rendered to a participant for which they received the benefit of service.

(IV) "Colorado Energy Office" means the Colorado Energy Office created in § 24-38.5-101, C.R.S.

(V) "Eligible low-income customer" means a residential utility customer who meets the household income thresholds pursuant to paragraph 3412(c).

(VI) "Fixed credit" means an annual bill credit established at the beginning of a participant's participation in a program each year delivered as a monthly credit on each participant's bill. The fixed credit is the participant's full annual bill minus the participant's affordable percentage of income payment obligation on the full annual bill.

(VII) "Full annual bill" means the current consumption of a participant billed at standard residential rates. The full annual bill of a participant is comprised of two parts: (1) that portion of the bill that is equal to the affordable percentage of income payment; and, (2) that portion of the bill that exceeds the affordable percentage of income payment.

(VIII) "LEAP" means Low-Income Energy Assistance Program, a county-run, federally-funded, program supervised by the Colorado Department of Human Services, Division of Low-Income Energy Assistance.

(IX) "LEAP participant" means a utility customer who at the time of applying to participate in a program has been determined to be eligible for LEAP benefits by the Department during either: (1) the Department's current six-month (November 1 – April 30) LEAP application period, if that period is open at the time the customer applies for program participation; or, (2) the Department's most recently closed six-month (November 1 – April 30) LEAP application period, if that period is closed at the time the customer applies to participate in the program and the Department's next six-month (November 1 – April 30) LEAP application period has not yet opened, provided, however, that in order to retain status as a LEAP participant under part (2) of this definition, the utility customer must apply to the Department during the Department's next six-month (November 1 – April 30) LEAP benefit application period and be determined eligible for such benefits.

(X) "Non-participant" means a utility customer who is not receiving low-income assistance under rule 3412.

(XI) "Participant" means an eligible low-income residential utility customer who is granted the reasonable preference or advantage through participation in an electric service low-income program.

(XII) "Percentage of Income Payment Plan" (or "PIPP") means a payment plan for participants that does not exceed an affordable percentage of their household income as set forth in subparagraph 3412(e)(I).

(XIII) "Program" means an electric service low-income program approved under rule 3412.

(XIV) "Program credits" means the amount of benefits provided to participants to offset the unaffordable portion of a participant's utility bill and /or dollar amounts credited to participants for arrearage forgiveness.

(XV) "Unaffordable portion" means the amount of the estimated full annual bill that exceeds the affordable percentage of income payment.

(c) Participant eligibility. Eligible participants are limited to those with a household income at or below 185 percent of the current federal poverty level and who otherwise meet the eligibility criteria set forth in rules of the Colorado Department of Human Services adopted pursuant to § 40-8.5-105, C.R.S.

(I) The utility shall obtain household income information from LEAP.

(II) If a participant's household income is $0, the utility may establish a process that verifies income on a more frequent basis.

(III) Program participants shall not be required to make payment on their utility account as a condition of entering into the program.

(d) Enrollment. Utilities shall be responsible for the methods by which participant enrollment in their approved low income program is obtained and sustained, however the utility should engage in enrollment processes that are efficient and attempt to maximize the potential benefits of participation in the low income program by low income customers.

(e) Payment plan.

(I) Participant payments for electric bills rendered to participants shall not exceed an affordable percentage of income payment. The percentage of a participant's household income for which the participant is responsible shall be determined as follows:

(A) for electric accounts for which electricity is the primary heating fuel, participant payments shall be no lower than three percent and not greater than six percent of the participant's household income; and

(B) for electric accounts for which electricity is not the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income.

(II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.

(III) Notwithstanding the percentage of income limits established in subparagraph 3412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of $0, provided that:

(A) the participant's minimum payment for an electric heating account shall be no more than $20.00 a month; and

(B) the participant's minimum payment for an electric non-heating account shall be no more than $10.00 a month.

(IV) Full annual bill calculation. The utility shall be responsible for estimating a participant's full annual bill for the purpose of determining the unaffordable portion of the participant's full annual bill delivered as a fixed credit on the participant's monthly billing statement.

(V) Fixed credit benefit. The fixed credit shall be adjusted during a program year in the event that standard residential rates, including commodity or fuel charges change to the extent that the full annual bill at the new rates would differ from the full annual bill upon which the fixed credits are currently based by 25 percent or more.

(VI) Levelized budget billing participation. A utility shall enroll participants in its levelized budget billing program as a condition of participation in the program. Should a participant fail to meet monthly bill obligations and be placed by a utility in its regular delinquent collection cycle, the utility may remove the participant from levelized budget billing in accordance with the utility's levelized budget billing tariff.

(VII) Arrearage credits.

(A) Arrearage credits shall be applied to pre-existing arrearages.

(B) Arrearage credits shall be sufficient to reduce, when combined with participant copayments, if any, the pre-existing arrearages to $0.00 over a period not less than one month and not more than twenty-four months.

(C) Application of an arrearage credit to a participant account may be conditioned by the utility on one or more of the following:

(i) the receipt of regular participant payments toward bills for current usage; or

(ii) the payment of a participant copayment toward the arrearages so long as the participant's copayment total dollar amount does not exceed one percent of gross household income.

(D) Should the participant exit the program prior to the full forgiveness of all pre-existing arrearages, the amount of remaining pre-existing arrearages shall become due in accordance with the utilities tariff filed under rules 3401, 3407, and 3408.

(E) Pre-existing arrears under this subparagraph shall not serve as the basis for the termination of service for nonpayment or as the basis for any other utility collection activity while the customer is participating in the program.

(F) A participant may receive arrearage credits under this section even if that participant does not receive a credit toward current bills, if the participant enters into and maintains a levelized budget billing plan.

(VIII) Portability of benefits. A participant may continue to participate without reapplication should the participant change service addresses, but remain within the service territory of the utility providing the benefit, provided that the utility may make necessary adjustments in the levelized budget billing amount to reflect the changed circumstances. A participant who changes service addresses and does not remain within the service territory of the utility providing the benefit must reapply to become a participant at the participant's new service address.

(IX) Payment default provisions. Failure of a participant to make his or her monthly bill payments will result in a utility placing the participant in its regular collection cycle. Missed, partial or late payments shall not result in the removal of a participant from the program.

(f) Program implementation.

Each utility shall maintain effective terms and conditions in its tariffs on file with the Commission containing its low-income program.

(g) Cost recovery.

(I) Each utility shall include in its low income tariff terms and conditions how costs of the program will be recovered.

(II) Program cost recovery.

(A) Program cost recovery shall be based on a fixed monthly fee.

(B) The maximum impact on residential rates shall be no more than $00.31 per month.

(C) In order to determine monthly rates applicable to rate classes other than residential, program costs shall be allocated to each retail rate based on each rate class's share of the test year revenue requirement established in the utility's last Phase II rate case, or under another reasonable methodology supported by quantifiable information. The monthly rate per this subparagraph to be charged each rate schedule customer shall be clearly stated on a tariff sheet.

(D) Utilities shall separately account for the cumulative program cost recovery and cumulative program and administrative costs to determine if the net of program cost recovery and program and administrative cost are in balance during the program year.

(i) By December 31, 2016, utilities shall determine if the total cumulative cost recovery amount exceeds total cumulative program and administrative costs through September 30, 2016. If at that time total cumulative cost recovery exceeds total cumulative program and administrative costs by 50 percent or more, the over collected amount shall be refunded to all customers in accordance with rule 3410.

(ii) Beginning December 31, 2017 and in each year thereafter, the utility shall file a report with the Commission in the most recent miscellaneous proceeding for annual low-income filings detailing the net difference between program cost recovery and program costs as of September 30 of each year.

(1) Should the net difference of program cost recovery over program costs be greater than 50 percent derived in (ii) above, either positive or negative, and the utility is not currently at the maximum impact for non-participants, the utility shall file with the Commission an advice letter and tariff pages seeking approval for the rates determined in subparagraph 3412(g)(II)(D) in order to bring the projected recovery in balance for the ensuing 12 month period. The revised charge shall not exceed the maximum impact for non-participants in subparagraph 3412(g)(II)(C).

(III) The following costs are eligible for recovery by a utility as program costs:

(A) program credits or discounts applied against bills for current usage.

(B) program credits applied against pre-existing arrearages.

(C) program administrative costs; and

(D) Commission-sponsored program evaluation costs required under paragraph 3412(k)

(IV) The utility shall apply, as an offset to cost recovery, all program expenses attributable to the program. Program expenses include utility operating costs; changes in the return requirement on cash working capital for carrying arrearages; changes in the cost of credit and collection activities directly related to low-income participants; and changes in uncollectable account costs for these participants.

(V) LEAP grants.

The utility shall apply energy assistance grants provided to the participant by the LEAP program to the dollar value of credits granted to individual program participants.

(A) A utility shall apply any energy assistance benefit granted to the participant by LEAP to that portion of the program participant's full annual bill that exceeds the participant's affordable percentage of income payment.

(B) If the dollar value of the energy assistance grant is greater than the dollar value of the difference between the program participant's full annual bill and the participant's affordable percentage of income payment, the dollar amount by which the energy assistance grant exceeds the difference will be applied:

(i) first, to any pre-existing arrearages that at the time of the energy assistance grant continues to be outstanding; and

(ii) second, to the account of the program participant as a benefit to the participant.

(C) No portion of an energy assistance or LEAP grant provided to a program participant may be applied to the account of a participant other than the participant to whom the energy assistance grant was rendered.

(D) If an all-electric utility's low-income customers do not benefit widely from LEAP grants, the utility shall not apply the dollar value of credits granted to individual LEAP grantees to the dollar value of credits granted to individual program participants.

(h) Other programs. In addition to the utility's low-income program, with Commission approval, a utility may offer other rate relief options to eligible households.

(I) Other programs offered by the utility under rule 3412 must be intended to reach low-income households that do not substantially benefit from the provisions of the low-income program. Such programs may take the form of discount rates, tiered discount rates or other direct bill relief methods where the low-income household benefitting from the program is granted a reasonable preference in tariffed rates assessed to all residential utility customers.

(II) Cost recovery for other programs combined with the Percentage of Income Payment Plan shall not exceed the maximum impact on residential rates described in subparagraph 3412(g)(II)(C).

(i) Energy efficiency and weatherization.

(I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the state of Colorado or other entities.

(II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual electricity usage exceeds 10,000 kWh annually.

(j) Stakeholder engagement. A utility shall conduct annual meetings with low-income stakeholders for the purpose of seeking solutions to issues of mutual concern and aligning program practices with the needs of customers and other stakeholders.

(k) Program evaluation. A triennial evaluation of the program provisions under rule 3412 beginning in 2019 shall be undertaken in order to review best practices in similar low-income assistance programs in existence in other regulatory jurisdictions, as well as evaluate operation of each utility's program for effectiveness in achieving optimum support being provided to low income participants. The evaluation shall also recommend modifications if available that improve the delivery of benefits to participants and increase the efficiency and effectiveness of each program as they exist at the point of evaluation.

(I) Procurement of the third-party vendor that will perform the evaluation will be undertaken by the Colorado Energy Office. The CEO shall seek the involvement of interested stakeholders including, but not limited to, Commission staff, all Commission regulated electric and gas utilities, LEAP, the Office of Consumer Counsel, and Energy Outreach Colorado in the design of the requirements regarding study focus and final reporting.

(II) Approval of the third-party vendor shall be the responsibility of the Commission. The CEO shall file with the Commission in the most recent annual report proceeding, a request for approval of the contract of the vendor selected. The Commission shall review and act on the request within 30 days.

(III) $00.0013 per customer per month shall be set aside by the utility starting in the 2016-2017 program year in order to fund the triennial evaluation of the program evaluation described in paragraph 3412(k).

(IV) The dollars resulting from the $00.0013 charge shall be recovered as a program cost under subparagraph 3412(f)(IV).

(V) The evaluation will be filed by Commission staff in the most recent miscellaneous proceeding for annual low income filings.

(VI) Staff and the CEO will assess the individual utilities' deferred balances set aside for the program evaluation starting in 2019 at the conclusion of the third program year and each three years thereafter and will determine the amounts each utility is to remit to the third party evaluator based on the contractual terms approved by the Commission for the evaluation.

(l) Annual report. No later than December 31, 2016, each utility shall file a report in the most recent miscellaneous proceeding for annual low-income filings using the form available on the Commission's website, based on the seven-month period April 1, 2016 through October 31, 2016, and then on November 30 each of the following years, based on each 12-month period ending October 31, containing the following information:

(I) monthly information on the program including number of participants, amount of benefit disbursement, type of benefit disbursement, LEAP benefits applied to the unaffordable portion of participant's bills, administrative costs, and revenue collection;

(II) the number of applicants for the program;

(III) the number of applicants qualified for the program;

(IV) the number of participants;

(V) the average assistance provided, both mean and median;

(VI) the maximum assistance provided to an individual participant;

(VII) the minimum assistance provided to an individual participant;

(VIII) total cost of the program and the average rate impact on non-participants by rate class, including impact based on typical monthly consumption of both its residential and small business customers;

(IX) the number of participants that had service discontinued as a result of late payment or non-payment, and the amount of uncollectable revenue from participants;

(X) an estimate of utility savings as a result of the implementation of the program (e.g., reduction in trips related to discontinuance of service, reduction in uncollectable revenue, etc.);

(XI) the average monthly and annual total electric consumption in PIPP participants' homes;

(XII) the average monthly and annual total electric consumption in the utility's residential customer's homes;

(XIII) the number of program participants referred to the weatherization program;

(XIV) a description of the ways in which the program is being integrated with existing energy efficiency of DSM programs offered by the utility;

(XV) a description of the ways in which the program is being integrated with existing weatherization programs offered by the state of Colorado;

(XVI) a description of program outreach strategies and metrics that illustrate the effectiveness of each outreach strategy;

(XVII) the number of participants at the start of the program year that the utility removed for any reason, the number of potential participants rejected because of the existence of a cap on the program, the period of arrearage time from date participants became eligible and were granted arrearage forgiveness, and the number of participants who came back as eligible participants in the program year after being eligible in a prior program year and were provided arrearage credits in the program year; and

(XVIII) a narrative summary of the utility's recommended program modifications based on report findings.

3413. Medical Exemption from Tiered Rate Plans.

(a) Scope and Applicability.

(I) Any electric utility that has a Commission approved tiered rate plan, also known as inverted block rates, shall file an advice letter and tariff, consistent with 4 CCR 723-1-1210, for a rate plan for residential customers who elect an alternate rate plan due to a qualifying medical condition and/or use of an essential life support device and whose household income is less than or equal to two hundred and fifty percent of federal poverty guidelines. The effect of such an exemption shall be neutral with respect to the utility's revenue requirement. If a customer qualifies for the alternate rate plan, that customer shall not be precluded from participating in any low-income program offered by the utility.

(II) If an electric utility requests Commission approval of a tiered rate plan after July 1, 2013, the utility shall include in its tiered rate plan request, a rate plan for customers with a qualifying medical condition and/or use of qualifying life support equipment.

(III) Rule 3413 is applicable to investor-owned electric utilities subject to rate regulation by the Commission.

(b) Definitions.

(I) "Essential life support device" means any medical device used in the home to sustain life or which is relied upon for mobility, as determined by a physician currently licensed and in good standing in the state of Colorado.

(II) "Federal poverty guidelines" means the poverty measures published annually by the U.S. Department of Health and Human Services.

(III) "Non-participant" means a utility customer who is billed according to the utility's tiered rate plan.

(IV) "Participant" means a residential utility customer who is billed according to the utility's alternative rate plan.

(V) "Qualifying medical condition" includes heat-sensitive medical conditions including, but not limited to, multiple sclerosis, epilepsy, quadriplegia, and paraplegia, or the need for the use of an essential life support device, as determined by a physician licensed in the state of Colorado.

(c) Certification of a qualifying medical condition and/or use of essential life support equipment shall be valid for one year. Once certified by a physician, customers with qualifying medical conditions lasting longer than one year may submit an annual attestation as to the continued condition and the current address of residency. Certification of a qualifying medical condition and/or use of essential life support equipment shall:

(I) be in writing;

(II) be sent from the office of a currently licensed physician in good standing in the state of Colorado to either the utility or a Commission approved third party with whom the utility contracts pursuant to rule 3209;

(III) clearly state the name of the customer or individual whose medical condition and/or use of life support equipment is at issue; and

(IV) clearly state the Colorado medical identification number, phone number, name, and signature of the physician or health care practitioner acting under a physician's authority certifying the existence of a qualifying medical condition and/or use of essential life support equipment.

(d) Such certification shall be incontestable by the utility as to the medical judgment, although the utility may use reasonable means to verify the authenticity of such certification.

(e) Verification of the authenticity of the certification of a qualifying medical condition or use of essential life support equipment shall be done by the utility or a Commission approved third party with which the utility contracts the medical verification activities.

(f) If the utility or Commission approved third party deems it reasonably necessary, verification of household income may be done by the utility or Commission approved third party with which the utility contracts the income verification activities.

(g) The Commission may, with cause, conduct an audit of the income verification process employed by the utility or an entity with which the utility contracts for that purpose.

(h) Cost recovery.

(I) Each utility shall address in its filing how costs of the alternative rate plan will be recovered.

(II) Each utility shall provide information regarding impacts on the various participant classes and on participants within a class.

(III) The following costs are eligible for recovery by a utility as alternative rate plan costs:

(A) lost revenues based on the difference between the expected monthly revenues and revenues under the alternate rate plan for the months during which a tiered rate plan is in place; and

(B) alternative rate plan administrative costs.

(i) Annual Report.

(I) No later than December 15 each year, each utility shall file an annual report, based on the previous summer cooling period during which tiered rates were in effect, containing the following information:

(A) monthly information including number of participants, individual household electricity usage, and individual household incomes;

(B) the total number of applicants for the alterative rate plan;

(C) the number of applicants who qualified for the rate plan; and

(D) total cost of the program and the average rate impact of non-participants by rate class.

(II) To the extent that the annual report may disclose individual customer information, the utility is authorized to file that portion of the annual report as confidential pursuant to 4 CCR 723-1-1102, Procedures Relating to Confidential Information Submitted to the Commission Outside of a Formal Proceeding.

3414. - 3499. [Reserved].

UNREGULATED GOODS AND SERVICES

3500. Overview and Purpose.

The purpose of these rules is to establish cost assignment and allocation principles to assist the Commission in setting just and reasonable rates and to ensure that utilities do not use ratepayer funds to subsidize non-regulated activities, in accordance with § 40-3-114, C.R.S. In order to promote these purposes, these rules also specify information that utilities must provide to the Commission. In providing for review of a utility's specific cost allocations in other states and jurisdictions, the rules merely contemplate a methodology to allow interested parties to obtain complete information regarding cost allocations. These rules do not expressly or implicitly allow this Commission to order a utility to revise its cost allocations in other jurisdictions or states.

3501. Definitions.

The following definitions apply only to rules 3501 through 3505. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Activity" means a business activity, product or service whether offered by a Colorado utility, a division of a Colorado utility, or an affiliate of a Colorado utility.

(b) "Allocate" or "Allocated" or "Cost allocation" means to distribute a joint or common cost to or from more than one activity or jurisdiction.

(c) "Cost assignment" means a cost that is specifically identified with a particular activity or jurisdiction and charged directly to that activity or jurisdiction. At no point in the process of making the cost assignment is an allocation applied.

(d) "Cost assignment and allocation manual" (CAAM) means the indexed document filed by a utility with the Commission that describes and explains the cost assignment and allocation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the cost assignment and allocation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.

(e) "Division" means an activity conducted by a Colorado utility but not through a legal entity separate from the Colorado utility. It includes the electric, gas, or thermal activities of a Colorado utility and any non-regulated activities provided by the Colorado utility.

(f) "Fully distributed cost" means the process of segregating, assigning, and allocating the revenues, expenses, assets, liabilities and rate base amounts recorded in the utility's accounting books and records using cost accounting, engineering, and economic concepts, methods and standards. Fully distributed cost includes a return on investment in cases where assets are used.

(g) "Fully distributed cost study" is a cost study that reflects the result of the fully distributed revenues, expenses, assets, liabilities and rate base amounts for the Colorado utility to and from the different activities, jurisdictions, divisions, and affiliates using cost accounting, engineering, and economic concepts, methods, and standards.

(h) "Jurisdictional" means having regulatory rate authority over a utility. Jurisdiction can be at a state or federal level.

(i) "Regulated activity" means any activity that is offered as a public utility service as defined in Title 40, Articles 1 to 7 C.R.S., and is regulated by the Commission or regulated by another state utility commission or the FERC, or any non-regulated activity which meets the criteria specified in rules 3502(g).

(j) "Non-regulated activity" means any activity that is not offered as a public utility service as defined in Title 40, Articles 1 to 7, C.R.S., and is not regulated by this Commission or another state utility commission or the FERC.

(k) "Transaction" means the activity that results in the provision of products, services, or assets by one division or an affiliate to another division or an affiliate.

3502. Cost Assignment and Allocation Principles.

In determining fully distributed cost, the utility shall apply the following principles (listed in descending order of required application in paragraphs (a), (b) and (c) below):

(a) Tariff services provided to an activity will be charged to the activity at the tariff rates.

(b) If only one activity or jurisdiction causes a cost to be incurred, that cost shall be directly assigned to that activity or jurisdiction.

(c) Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions. Each cost category shall be fairly and equitably allocated between regulated and non-regulated activities or jurisdictions in accordance with the following principles:

(I) Cost causation. All activities or jurisdictions that cause a cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can easily be traced to the specific activity or jurisdiction.

(II) Variability. If the fully distributed cost study indicates a direct correlation exists between a change in the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.

(III) Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred.

(IV) Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

(V) Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator to be defined in the utility's CAAM.

(d) For cost assignment and allocation purposes, the value of all transactions from the Colorado utility to a non-regulated activity shall be determined as follows.

(I) If the transaction involves a product or service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate.

(II) If the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the higher of the utility's fully distributed cost or market price. Market price shall be either the price charged by the utility, or if this condition cannot be met, the lowest price charged by another person for a comparable product or service.

(III) If the transaction involves the sale of an asset, the value of the transaction shall be the higher of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be the higher of fully distributed cost or market price. Market price shall be either the price charged by the utility or if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, when such prices are publicly available.

(e) For cost assignment and allocation purposes, the value of all transactions from a non-regulated activity to the utility shall be determined as follows.

(I) If the transaction involves a product or service that is not provided pursuant to a tariff, the value of the transaction shall be the lower of the fully distributed cost or the market price except if the transaction results from a competitive solicitation process then the value of the transaction shall be the winning bid price. Fully distributed cost in this circumstance, shall be the cost that would be incurred by the utility to provide the service internally. Market price shall be either the price charged by the supplying non-regulated activity or if that condition is not met, the lowest price charged by other persons in the market for a comparable product or service, when such prices are publicly available.

(II) If the transaction involves the sale of an asset, the value of the transaction shall be the lower of net-book cost or market price. If the transaction involves the use of an asset, the value of the transaction shall be at the lower of fully distributed cost or market price. Market price shall be either the price charged by the non-regulated activity or, if this condition cannot be met, the lowest price charged by another person in the market for the sale or use of a comparable asset, where such prices are publicly available.

(f) If it is impracticable for the utility to establish a market price pursuant to paragraphs (d) or (e), the utility shall provide a statement to that effect, including its reasons in its fully distributed cost study as well as its proposed method and amount for valuing the transaction. Parties in a Commission proceeding retain the right to advocate alternative market prices pursuant to paragraphs (d) and (e).

(g) A utility may classify non-jurisdictional services as regulated if the services are rate-regulated by another agency (i.e., another state utility commission or the FERC) and where there are agency-accepted principles or methods for the development of rates associated with such services. This rule may apply, for example, to a provider's wholesale sales of electric power and energy. For such services, the utility shall identify the services in its manual, and account for the revenues, expenses, assets, liabilities, and rate base associated with these services as if these services are regulated.

(h) For cost assignment and allocation purposes, the value of all transactions between regulated divisions within a utility shall be determined as follows:

(I) If the transaction involves a service provided by the utility pursuant to tariff, the value of the transaction shall be at the tariff rate.

(II) If the transaction involves a service or function that is not provided pursuant to a tariff, the value of the transaction shall be at cost.

(i) If the utility offers a service that is a combination of regulated and non-regulated activities (i.e., a bundled service), the utility shall assign and/or allocate costs to the regulated and non-regulated activities separately.

(j) A utility may classify incidental activities as regulated activities. If an incidental activity is classified as a regulated activity, the utility shall clearly identify the activity as an incidental activity, and account for the revenues, expenses, assets, liabilities and rate base items as if that activity were a regulated activity.

(k) To the extent possible, all assigned and allocated costs between regulated and non-regulated activities should have an audit trail which is traceable on the books and records of the applicable regulated utility to the applicable accounts pursuant to the Federal Energy Regulatory Commission Uniform System of Accounts.

(l) In a rate proceeding involving the calculation of revenue requirements, a complaint proceeding where cost assignments or allocations are at issue, or a proceeding where CAAM approval is sought, the utility or any party may advocate a cost allocation principle other than that already in use, if the Commission has already approved the principle for that cost. The party requesting the alternative approach shall have the burden of proving the need for an alternative principle and why the particular principle is appropriate for the particular cost.

3503. Cost Assignment and Allocation Manuals.

(a) Each utility shall maintain on file with the Commission an approved indexed cost assignment and allocation manual which describes and explains the calculation methods the utility uses to segregate and account for revenues, expenses, assets, liabilities, and rate base cost components assigned or allocated to Colorado jurisdictional activities. It includes the calculation methods to segregate and account for costs between and among jurisdictions, between regulated and non-regulated activities, and between and among utility divisions.

(b) Each utility shall include the following information in its CAAM.

(I) A listing of all regulated or non-regulated divisions of the Colorado utility together with an identification of the regulated or non-regulated activities conducted by each.

(II) A listing of all regulated or non-regulated affiliates of the Colorado utility together with an identification of which affiliates allocate or assign costs to and from the Colorado utility.

(III) A listing and description of each regulated and non-regulated activity offered by the Colorado utility. The Colorado utility shall provide a description in sufficient detail to identify the types of costs associated with the activity and shall identify how the activity is offered to the public and identify whether the Colorado utility provides the activity in more than one state. If an activity is offered subject to tariff, the Colorado utility may identify the tariff and the tariff section that describes the service offering in lieu of providing a service description.

(IV) A listing of the revenues, expenses, assets, liabilities and rate base items by Uniform System of Accounts (USOA) account number that the utility proposes to include in its revenue requirement for Colorado jurisdictional activities including those items that are partially allocated to Colorado as well as those items that are exclusively assigned to Colorado.

(V) A detailed description showing how the revenues, expenses, assets, liabilities and rate base items by account and sub-account are assigned and/or allocated to the Colorado utility's non-regulated activities, along with a description of the methods used to perform the assignment and allocations.

(VI) A description of each transaction between the Colorado utility and a non-regulated activity which occurred since the Colorado utility's prior CAAM was filed and, for each transaction, a statement as to whether, for this Commission's jurisdictional cost assignment and allocation purposes, the value of the transactions is at cost or market as applicable.

(VII) A description of the basis for how the assignment or allocation is made.

(VIII) If the utility believes that specific cost assignments or allocations are under the jurisdiction of another authority, the utility shall so state in its CAAM and give a written description of the prescribed methods. Nothing herein shall be construed to be a delegation of this Commission's ratemaking authority related to those assignments or allocations.

(IX) Any additional information specifically required by Commission order.

(c) A utility may treat certain transactions as confidential pursuant to the Commission rules on confidentially.

(d) Following the initial approval of its CAAM, the utility shall file an updated CAAM in each rate case proceeding where revenue requirements are determined or every five years following approval of the CAAM then in effect, whichever is earlier.

(e) The utility may, at its discretion, file an application seeking Commission approval of updates to its CAAM at any time.

(f) Whenever a utility files for approval of an update to its CAAM as a result of paragraph (f) or (g) above, the utility shall also simultaneously file a FDC study reflecting the results of the cost allocation methods in its updated manual.

(g) Each utility shall maintain all records and supporting documentation concerning its CAAMs for so long as such manual is in effect or are subject to a complaint or a proceeding before the Commission.

3504. Fully Distributed Cost Study.

(a) The utility shall submit its fully distributed cost study in both electronic and paper format simultaneously with filing its CAAM for all Colorado divisions and activities.

(b) The utility shall prepare a FDC study that identifies all the non-regulated activities provided by each division in Colorado. The FDC study shall show the revenues, expenses assets, liabilities and rate base items assigned and allocated to each non-regulated activity. If the utility has more than one division (e.g., gas, electric, thermal or non-utility) in Colorado, the FDC study shall include a summary of all assigned and allocated costs by division.

(c) In preparation of its FDC study, the utility shall complete an analysis of each non-regulated activity to identify the costs that are associated with and/or should be charged to each non regulated activity to ensure each non-regulated activity is assigned and allocated the appropriate amount of revenues, expenses, assets, liabilities and rate base items.

(d) If the CAAM is filed in connection with a rate case, the FDC study shall be based on the same test year used in the utility's rate case filing. The utility's FDC study shall include revenues, expenses, assets, liabilities and rate base items in order for the Commission to determine if all appropriate revenues, expenses, assets, liabilities and rate base items have been appropriately assigned and allocated, and to determine the utility's compliance with the principles established in rule 3502. For each assignment and allocation the utility shall:

(I) Identify the revenues, expenses, assets, liabilities and rate base items by account number, sub-account number and account description; and

(II) For each account in (I) above, identify the assignment and allocation method used to assign and allocate costs in sufficient detail to verify the assignment and allocation method used to assign and allocate costs to Colorado divisions and activities is accurate and consistent with the utility's CAAM methodology and reference the CAAM section that describes the allocation.

(III) Provide the test year dollar itemized amounts of revenues, expenses, assets, liabilities, and rate base assigned and allocated to each Colorado division and non-regulated activity; the itemized amounts assigned and allocated to the Colorado utility for regulated activities; the itemized amounts assigned and allocated to the Colorado utility for Colorado non-regulated activities; and the itemized amounts assigned and allocated to other jurisdictions.

(e) Each utility shall maintain all records and supporting documentation concerning its FDC study for so long as such study is in effect or are subject to a complaint or a proceeding before the Commission.

3505. Disclosure of Non-regulated Goods and Services.

Whenever a Colorado utility engages in the provision or marketing of non-regulated goods or services in Colorado that are not subject to Commission regulation, and the Colorado utility's name or logo is used in connection with the provision of such non-regulated goods and services in Colorado, there must be conspicuous, clear, and concise disclosure to prospective customers that such non-regulated goods and services are not regulated by the Commission. Such disclosure to prospective customers in Colorado shall be included in all Colorado advertising or marketing materials, proposals, contracts, and bills for non-regulated goods and services, regardless of whether the Colorado utility provides such non-regulated goods or services in Colorado directly or through a division or affiliate.

3506. – 3599. [Reserved].

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject to the requirements in rule 3605.

3601. Overview and Purpose.

The purpose of these rules is to establish a process to determine the need for additional electric resources by electric utilities subject to the Commission's jurisdiction and to develop cost-effective resource portfolios to meet such need reliably. It is the policy of the state of Colorado that a primary goal of electric utility resource planning is to minimize the net present value of revenue requirements. It is also the policy of the state of Colorado that the Commission gives the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.

3602. Definitions.

The following definitions apply to rules 3600 through 3619. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Availability factor" means the ratio of the time a generation facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured.

(b) "Annual capacity factor" means the ratio of the net energy produced by a generation facility in a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity year round.

(c) "Cost-effective resource plan" means a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact.

(d) "Demand-side resources" means energy efficiency, energy conservation, load management, and demand response or any combination of these measures.

(e) "End-use" means the light, heat, cooling, refrigeration, motor drive, or other useful work produced by equipment that uses electricity or its substitutes.

(f) "Energy conservation" means the decrease in electricity requirements of specific customers during any selected time period, resulting in a reduction in end-use services.

(g) "Energy efficiency" means the decrease in electricity requirements of specific customers during any selected period with end-use services of such customers held constant.

(h) "Heat rate" means the ratio of energy inputs used by a generation facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kWh.

(i) "Modeling error or omission" means any incorrect, incomplete, or improper input to computer-based modeling performed by the utility, for evaluating a proposed resource, of a magnitude that alters the model results.

(j) "Net present value of revenue requirements" means the current worth of the total expected future revenue requirements associated with a particular resource portfolio, expressed in dollars in the year the plan is filed as discounted by the appropriate discount rate.

(k) "Planning period" means the future period for which a utility develops its plan, and the period, over which net present value of revenue requirements for resources are calculated. For purposes of this rule, the planning period is twenty to forty years and begins from the date the utility files its plan with the Commission.

(l) "Potential resource" means a generation facility or energy storage system bid into a competitive acquisition process in accordance with an approved resource plan.

(m) "Renewable energy resources" means all renewable energy resources as defined in the Commission's RES Rules.

(n) "Resource acquisition period" means the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The resource acquisition period begins from the date the utility files its plan with the Commission.

(o) "Resource plan" or "plan" means a utility plan consisting of the elements set forth in rule 3604.

(p) "Resources" means supply-side resources, energy storage systems and demand-side resources used to meet electric system requirements.

(q) "Section 123 resources" means new energy technology or demonstration projects, including new clean energy or energy-efficient technologies under § 40-2-123(1)(a), C.R.S. and § 40-2-123(1)(c), C.R.S., and Integrated Gasification Combined Cycle projects under § 40-2-123(2), C.R.S.

(r) "Supply-side resources" means resources that provide electrical energy or capacity to the utility. Supply-side resources include utility owned generation facilities and energy or capacity purchased from other utilities and non-utilities.

(s) "Typical day load pattern" means the electric demand placed on the utility's system for each hour of the day.

3603. Resource Plan Filing Requirements.

(a) Jurisdictional electric utilities shall file a resource plan pursuant to these rules every four years beginning October 31, 2015. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to rule 3604. If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(b) Each jurisdictional electric utility shall contemporaneously file with its resource plan submitted under paragraph 3603(a), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to paragraph 3604(j) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the resource plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

3604. Contents of the Resource Plan.

The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work papers to support the information contained in the plan. The plan shall include the following.

(a) A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.

(b) An annual electric demand and energy forecast developed pursuant to rule 3606.

(c) An evaluation of existing resources developed pursuant to rule 3607.

(d) An evaluation of transmission resources pursuant to rule 3608.

(e) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.

(f) An assessment of the need for additional resources developed pursuant to rule 3610.

(g) The utility's plan for acquiring these resources pursuant to rule 3611, including a description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

(h) The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

(i) The proposed RFP(s) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3616.

(j) A list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource in RFP documents or under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(k) Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the RES, 4 CCR 723-3-3650, et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.

(l) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, including peer-reviewed studies, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(m) Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

(n) The utility shall propose how energy storage systems smaller than 30 MW in size may be accommodated in the all-source competitive acquisition process.

3605. Cooperative Electric Generation and Transmission Association Requirements

This rule shall apply to each utility that is a cooperative electric generation and transmission association.

The statutory authority for this rule can be found at § 40-2-134, C.R.S.

(a) Electric resource plan filing requirements.

(I) Initial plan filing. Each utility shall file an assessment of existing resources pursuant to paragraph 3605(c) no later than June 1, 2020. The utility shall file the assessment as a report and also may submit prefiled testimony. The Commission shall open an adjudicatory proceeding to accept the report and shall establish a notice and intervention period for the determination of the parties. Parties may conduct discovery on the report and on any prefiled testimony submitted with the report. No later than December 1, 2020, the utility shall file an application for approval of the plan with all remaining required components of the plan in accordance with subparagraph 3605(a)(IV). The complete plan will initiate Phase I as set forth in paragraph 3605(g).

(II) Subsequent plan filings. Each utility shall file an electric resource plan pursuant to these rules every four years beginning June 1, 2023. In addition to the required four-year cycle, a utility may file an interim plan, pursuant to subparagraph 3605(a)(IV). If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(III) Highly confidential information. Each utility shall contemporaneously file with its resource plan submitted under subparagraphs 3605(a)(I) and 3605(a)(II), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to subparagraph 3605(a)(III)(K) and consistent with rule 1101 of the Commission's Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility's motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the resource plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

(IV) Plan components. The plan shall contain the information specified below. When required by the Commission, the utility shall provide work papers to support the information contained in the plan. The plan shall include the following.

(A) The proposed resource acquisition period; however, the resource acquisition period for the initial plan filing submitted in accordance with subparagraph 3605(a)(I) shall extend through 2030. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(B) An annual electric demand and energy forecast developed pursuant to paragraph 3605(b).

(C) An assessment of existing resources developed pursuant to paragraph 3605(c).

(D) An assessment of transmission resources pursuant to paragraph 3605(d).

(E) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to paragraph 3605(e).

(F) An assessment of the need for additional resources developed pursuant to paragraph 3605(f).

(G) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(H) The cost of the projected carbon dioxide emissions using the carbon cost calculated by the Commission based on the most recent assessment of the social cost of carbon developed by the federal government.

(I) The annual water consumption for each of the utility's existing generation resources and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(J) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts.

(K) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The protections sought by the utility for these items shall be specified in the motion(s) submitted under subparagraph 3605(a)(III). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

(L) An assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

(M) A proposed base case portfolio of resources and at least one proposed alternative portfolio of resources to calculate and to present the associated net present value of revenue requirements using the cost of carbon emissions established by the Commission. The utility also may propose different costs of carbon to be used with respect to the alternative portfolios of resources.

(N) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, consistent with the amounts of renewable energy resources the utility proposes to acquire.

(O) Studies, including updates to studies relied upon by the utility in previous electric resource plans, commissioned or prepared by the utility to support the development of its electric resource plan.

(P) Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

(Q) A detailed listing and explanation of the information the utility will provide in its ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(b) Electric energy and demand forecasts.

(I) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period.

(A) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated by state jurisdiction and by member of the cooperative electric generation and transmission association.

(B) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(C) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(D) Annual and coincident summer and winter peak system losses of the cooperative electric generation and transmission association.

(E) The electric demand placed on the utility's system for each hour of the day by state jurisdiction and by member of the cooperative electric generation and transmission association. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(II) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(III) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(IV) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(V) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

(c) Assessment of existing resources.

(I) Existing resource assessment. The utility shall describe its existing generation facilities and energy storage systems at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(A) Name(s) and location(s) of utility-owned and contracted generation and energy storage facilities.

(B) Rated capacity and net dependable capacity of utility-owned and contracted generation and energy storage facilities.

(C) Fuel type, average and marginal heat rates, quick start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation and energy storage facilities over the resource acquisition period.

(D) Estimated in-service dates for utility-owned generation and energy storage facilities not in service at the time the electric resource plan under consideration is filed.

(E) Estimated remaining useful lives of existing generation and energy storage facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(F) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(G) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(H) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this subparagraph 3605(c)(I).

(I) The expected demand-side resources during the resource planning period from existing measures installed through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association; and, from measures expected to be installed in the future through the demand-side management programs implemented by the members of the cooperative electric generation and transmission association.

(J) Unit-level revenue requirements of utility-owned and contracted generation facilities, including the following components: capital costs, operations and maintenance costs (fixed and variable), fuel costs, emissions and associated costs, integration and coal cycling costs, and energy and capacity payments (for contracted facilities).

(K) The performance characteristics of utility-owned energy storage systems including but not limited to: discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(L) The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(II) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(III) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

(d) Assessment of transmission resources.

(I) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(II) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to rule 3627 that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(III) For each transmission line or facility identified in subparagraph (d)(II), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(A) length and location;

(B) estimated in-service date;

(C) injection capacity;

(D) estimated costs;

(E) terminal points; and

(F) voltage and megawatt rating.

(IV) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(V) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

(e) Planning reserve margins and contingency plans.

(I) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(II) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under paragraph 3605(b), to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(III) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to paragraph 3605(f); or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under subparagraph 3605(h)(II).

(f) Assessment of need for additional resources.

(I) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to paragraph 3605(b), the assessment of existing resources developed pursuant to paragraph 3606(c), planning reserve margins developed pursuant to paragraph 3605(e), and other factors including, but not limited to, the factors listed in subparagraph 3605(f)(II).

(II) In assessing its need to acquire resources, the utility shall also:

(A) determine the additional eligible energy resources, if any, the utility will need to acquire to allow each member of the cooperative electric generation and transmission association in Colorado to comply with the Commission's RES rules;

(B) consider the benefits of energy storage system may provide to increase integration of intermittent resources; improve reliability; reduce the need for increased generation facilities to meet period of peak demand; and avoid, reduce, or defer investments; and

(C) address statewide goals to reduce greenhouse gas emissions in accordance with rules promulgated and implemented by Colorado Air Quality Control Commission.

(III) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

(g) Phase I.

(I) Review on the merits.

(A) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules of Practice and Procedure.

(B) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's filed electric resource plan.

(II) Utility plan for meeting the resource need.

(A) The utility shall specify the portion of the resource need that it intends to meet through a competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(B) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. The utility shall specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility.

(C) Although the utility may propose a method for acquiring new utility resources other than competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan filed under paragraph 3605(a) the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under paragraph 3605(f) exclusively through competitive bidding.

(D) The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources.

(E) The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(F) The utility shall propose a written bidding policy as part of its filing under paragraph 3605(a), including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner.

(G) Request for Proposals (RFPs).

(i) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to subparagraph 3605(g)(II). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(ii) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas and connecting to the utility's transmission system pursuant to paragraph 3605(d), including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; any physical and performance requirements for energy storage systems or instructions for bidders to explain characteristics of energy storage systems, including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations; methodologies or credit mechanisms to value energy storage services provided to the utility system; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(iii) The utility shall request from bidders the best value employment metrics for each bid resource and shall set forth criteria for the review of such metrics, based on objective performance standards, to be applied in the evaluation and selection of bids in accordance with § 40-2-129, C.R.S.

(iv) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility.

(III) Phase I decision.

(A) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan.

(B) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with paragraph 3605(a). If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(C) The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(i) The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

(ii) In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

(iii) The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

(iv) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

(D) The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

(E) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(h) Phase II.

(I) ERP Implementation Report.

(A) On or before the deadline established by the Commission, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan.

(i) The utility shall apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's Phase I decision.

(ii) The utility shall present a calculation of the net present value of revenue requirement for each portfolio required by the Phase I decision, including the defined base case portfolio. The utility shall present the net present value of revenue requirement for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Phase I decision and calculated without using the cost of carbon dioxide emissions. The utility also shall present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide.

(iii) The utility shall provide the Commission with the best value employment metrics information provided by bidders.

(B) Within 45 days after the filing of the utility's ERP Implementation Report, the parties in the electric resource plan proceeding may file comments on the utility's report.

(C) Within 60 days after the filing of the utility's ERP Implementation Report, the utility may file comments responding to the parties' comments.

(II) Phase II decision.

(A) Within 90 days after the receipt of the utility's ERP Implementation Report under subparagraph 3605(h)(I), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan.

(B) In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(C) In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

(D) In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

(E) In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

(III) Upon completion of Phase II, the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own. At a minimum the utility shall address the public release of highly confidential and confidential information in its ERP Implementation Report and all documents related to that report filed by the utility and the parties. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(IV) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

(i) Resource acquisitions not requiring interim or amended plans. The following resources need not be addressed by an interim or amended electric resource plan subsequent to Commission approval of a plan filed pursuant to paragraph 3605(a):

(I) emergency maintenance or repairs made to utility-owned generation and energy storage facilities;

(II) capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW;

(III) capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two-year term (including renewal terms) or for not more than 20 MW of capacity;

(IV) improvements or modifications to existing utility generation and energy storage facilities that change the production capability of the generation facility site in question, by not more than 20 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million; and

(V) modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 20 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

3606. Electric Energy and Demand Forecasts.

(a) Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period.

(I) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.

(II) Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.

(III) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(IV) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(V) Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.

(VI) Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(b) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(c) Required detail.

(I) In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.

(II) The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.

(d) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.

(e) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(f) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

3607. Evaluation of Existing Resources.

(a) Existing resource assessment. The utility shall describe its existing resources, all utility-owned generation facilities and energy storage systems for which the utility has obtained a CPCN from the Commission pursuant to § 40-5-101, C.R.S., at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(I) Name(s) and location(s) of utility-owned generation facilities and energy storage systems.

(II) Rated capacity and net dependable capacity of utility-owned generation facilities and energy storage systems.

(III) Fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities and availability factors for utility-owned energy storage systems over the resource acquisition period.

(IV) Estimated in-service dates for utility-owned generation facilities and energy storage systems for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.

(V) Estimated remaining useful lives of utility-owned generation facilities and energy storage systems without significant new investment or maintenance expense.

(VI) The amount of capacity and energy from generation facilities, energy storage systems, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems purchased pursuant to such contracts.

(VII) The amount of capacity and energy from generation facilities and energy storage systems provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems provided pursuant to such wheeling or coordination agreements.

(VIII) The performance characteristics of utility-owned energy storage systems including but not limited to discharge rates and durations, charging rates, response time; and cycling losses and limitations.

(IX) The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.

(X) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).

(XI) The expected demand-side resources during the resource planning period from existing measures installed through utility-administered programs; and, from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved plan.

(b) Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

3608. Transmission Resources.

(a) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(b) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., that, as identified in that report, could reasonably be placed into service during the resource acquisition period.

(c) For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(I) length and location;

(II) estimated in-service date;

(III) injection capacity and locations for generation facilities;

(IV) injection capacity and locations for energy storage systems;

(V) estimated costs;

(VI) terminal points; and

(VII) voltage and megawatt rating.

(d) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(e) The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

3609. Planning Reserve Margins and Contingency Plans.

(a) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(b) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(c) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610; or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The utility will identify the estimated costs it will incur in developing the contingency plan for addressing the acquisition of these resources (e.g., purchasing equipment options, establishing sites, engineering). The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3618(b)(II). The provisions of paragraph 3617(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.

3610. Assessment of Need for Additional Resources.

(a) By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to rule 3609, the utility shall assess the need to acquire additional resources during the resource acquisition period.

(b) In assessing its need to acquire additional resources, the utility shall also:

(I) Determine the additional eligible energy resources, if any, the utility will need to acquire to comply with the Commission's RES rules.

(II) Take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611.

(III) Consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability; reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.

(c) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

3611. Utility Plan for Meeting the Resource Need.

(a) It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation).

(b) Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(c) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition.

(d) Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its plan filed under rule 3603 the necessary bid policies, RFPs, and model contracts for common supply-side resources and energy storage systems necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.

(e) In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its plan submitted under rule 3603, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.

(f) The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide sufficient cost information in support of its proposal such that the Commission can reasonably compare the utility's proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery.

(g) Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate generation facility and energy storage system bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan. The utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits.

(h) In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the following best value employment metric information regarding each resource:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

3612. Independent Evaluator.

(a) Prior to the filing of the plan under rule 3603, the utility shall file for Commission approval the name of the independent evaluator who the utility, the Staff of the Commission, and the OCC jointly propose. Should the utility, the Commission Staff, and the OCC fail to reach agreement on an independent evaluator, the Commission shall refer the matter to an administrative law judge for resolution. In any event, the Commission shall approve an independent evaluator by written decision within 30 days of the filing of the plan under rule 3603.

(b) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(c) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its plan and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner so as to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. In the event that the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(d) All parties in the resource plan proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the resource plan proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any. Such log shall be posted weekly on the Commission's website for the duration of the independent evaluator's contract.

(e) In the event that the utility proposes a method for resource acquisition other than all-source competitive bidding, the Commission may retain the independent evaluator to assist the Commission in the rendering a decision on such alternative method for resource acquisition. The independent evaluator shall file a report with the Commission, prior to the evidentiary hearings, concerning its assessment of the costs and benefits that the utility has presented to the Commission to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through that alternative method of resource acquisition. The independent evaluator shall also address in its report whether the utility's proposed competitive acquisition procedures and proposed bidding policy, including the assumptions, criteria and models, are sufficient to solicit and evaluate bids in a fair and reasonable manner.

(f) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing. The Commission shall convene at least one procedural conference to establish a procedure related to questions to the independent evaluator from the utility and parties regarding the independent evaluator's filings in the proceeding.

3613. Bid Evaluation and Selection.

(a) Upon the receipt of bids in its competitive acquisition process, the utility shall investigate whether each potential resource meets the requirements specified in the resource solicitation and shall perform an initial assessment of the bids. Within 45 days of the utility's receipt of bids, the utility shall provide notice in writing by e-mail to the owner or developer of each potential resource stating whether its bid is advanced to computer-based modeling to evaluate the cost or the ranking of the potential resource, and, if not advanced, the reasons why the utility will not further evaluate the bid using computer-based modeling. If, after the utility issues notice to an owner or developer that the potential resource was not advanced to computer-based modeling, the utility subsequently advances that potential resource to computer-based modeling, the utility shall provide notice in writing by e-mail to the owner or developer of that potential resource within three business days of the utility's decision to advance the potential resource to computer-based modeling.

(b) For bids advanced to computer-based modeling, the utility shall, contemporaneously with the notification in paragraph 3613(a), also provide to the owner or developer the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the utility. The utility shall provide such information so that modeling errors or omissions may be corrected before the competitive acquisition process is completed. Such information shall explain to the owner or developer how its facility will be represented in the computer-based modeling and what costs, in addition to the bid information, will be assumed with respect to the potential resource. In the event that this information contains confidential or highly confidential information, the owner or developer shall execute an appropriate nondisclosure agreement prior to receiving this information.

(c) Within seven calendar days after receiving the modeling inputs and assumptions from the utility pursuant to paragraph 3613(b), the owner or developer of a potential resource shall notify the utility in writing by electronic mail the specific details of any potential dispute regarding these modeling inputs and assumptions. The owner or developer shall attempt to resolve this dispute with the utility. However, if the owner or developer and utility cannot resolve the dispute within three calendar days, the utility shall immediately notify the Commission with a filing in the resource plan proceeding. If the owner or developer is not already a party to the proceeding, the owner or developer shall file a notice of intervention as of right pursuant to paragraph 1401(b) of the Commission's Rules of Practice and Procedure, within one business day of the utility's filing of its notice of dispute to the Commission, for the limited purpose of resolving the disputed modeling inputs and assumptions related to the potential resource. An Administrative Law Judge (ALJ) will expeditiously schedule a technical conference at which the utility and the owner or developer shall present their dispute for resolution. The ALJ will enter an interim order determining whether corrections to the modeling inputs and assumptions are necessary. If the ALJ determines that corrections to the modeling inputs and assumptions are necessary, the utility shall, within three business days of the issuance of the ALJ's interim decision, provide the corrected information to both the owner or developer and the independent evaluator. In its report submitted under paragraph 3613(d), the utility shall also confirm by performing additional modeling as necessary, that the potential resource is fairly and accurately represented.

(d) Within 120 days of the utility's receipt of bids in its competitive acquisition process, the utility shall file a report with the Commission describing the cost-effective resource plans that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources as specified in the Commission's decision approving or rejecting the utility plan developed under rule 3604. In the event that the utility's preferred cost-effective resource plan differs from the Commission-specified scenarios, the utility's report shall also set forth the utility's preferred plan. The utility's plan shall also provide the Commission with the best value employment metrics information provided by bidders under rule 3616 and by the utility pursuant to rule 3611.

(e) Within 30 days after the filing of the utility's 120-day report under paragraph 3613(d), the independent evaluator shall separately file a report that contains the independent evaluator's analysis of whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported. The independent evaluator shall provide confidential versions of these reports to Commission staff and the OCC.

(f) Within 45 days after the filing of the utility's 120-day report under paragraph 3613(d), the parties in the resource plan proceeding may file comments on the utility's report and the independent evaluator's report.

(g) Within 60 days after the filing of the utility's 120-day report under paragraph 3613(d), the utility may file comments responding to the independent evaluator's report and the parties' comments.

(h) Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(i) The utility must complete the competitive acquisition process by executing contracts for potential resources within 18 months after the utility's receipt of bids in its competitive acquisition process. The utility may file a motion in the resource plan proceeding requesting to extend this deadline for good cause. The utility must execute final contracts for the potential resources prior to the completion of the competitive acquisition process to receive the presumption of prudence afforded by paragraph 3617(d).

(j) Upon completion of the competitive acquisition process pursuant to paragraph 3613(i), and consistent with the subsequent requirement for website posting of bids and utility proposals as required in paragraph 3613(k), protected information that was filed in the resource plan proceeding will be refiled as non-confidential or public information as specified in the Commission order described below. To satisfy this requirement the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own as a rate base investment. At a minimum the utility shall address its 120-day report in paragraph 3613(d), the independent evaluator's report in paragraph 3613(e), and all documents related to these reports filed by the utility, parties, or the independent evaluator. The utility shall file its proposal in the resource plan proceeding within 14 months after the receipt of bids in its competitive acquisition process. Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(k) Upon completion of the competitive acquisition process under paragraph 3613(i), the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

3614. Confidential Information Regarding Electric Generation Facilities and Energy Storage Systems.

(a) In any proceeding related to a resource plan filed under rule 3603, an amendment to an approved plan filed under rule 3619, or pursuant to a request for information made under paragraph 3615(b), the provisions regarding confidential information set forth in rules 1100 through 1103 of the Commission's Rules of Practice and Procedure shall apply, in addition to this rule 3614.

(b) The utility shall provide information claimed to be highly confidential under subparagraph 1101(b) to a reasonable number of attorneys representing a party in the resource plan proceeding, provided that those attorneys file appropriate non-disclosure agreements containing the terms listed in subparagraph 3614(b)(I). The utility shall also provide information claimed to be highly confidential under subparagraph 1101(b) to a reasonable number of subject matter experts representing a party in the resource plan proceeding, provided that the attorney representing the party files the appropriate non-disclosure agreements for the subject matter experts containing the terms in subparagraph 3614(b)(II) and the subject matter experts' curriculum vitae.

(I) Attorney highly confidential nondisclosure agreement terms.

I [attorney name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in, the course of this proceeding in Proceeding No. [ ], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will oversee the processes that any subject matter expert to whom I have authorized access to highly confidential information uses in order to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I will assure that extraordinary confidentiality provisions are properly implemented and maintained within my firm. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [ ] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(II) Subject Matter Expert highly confidential nondisclosure agreement terms.

I [subject matter expert's name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in the course of this proceeding in Proceeding No. [ ], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will work with my attorney, [attorney name], to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I did not and will not develop or assist in the development of any power supply proposals associated with this proceeding. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [ ] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(c) Paragraph 3614(b) is only applicable to proceedings related to a resource plan filed pursuant to rule 3603, an amendment to an approved plan filed under rule 3619, or to a request for information made under paragraph 3615(b).

(d) In the case where the utility claims that information provided pursuant to paragraphs 3604(m), 3607(a) or 3608(c) related to energy storage systems is confidential, the utility shall indicate whether or not such confidential information should be provided to developers and bidders responding to RFPs. The utility shall provide a proposed non-disclosure agreement to provide developers and bidders responding to RFPs confidential information deemed appropriate by the Commission.

(e) In addition to any other remedy available to the Commission, if the Commission finds that a developer or bidder has failed to comply with any applicable rules, laws, or any conditions approved by the Commission pursuant to paragraph 3614(d), the Commission may deem that developer or bidder ineligible to bid or develop storage systems in the subsequent ERP.

(f) In order to expedite access to confidential information at the beginning of the resource planning proceeding, an entity may file for intervention at any time during the 30-day notice period established in paragraph 1401(a) of the Commission's Rules of Practice and Procedure. If the entity requests an expedited decision on its motion, it shall include in the title of its motion for intervention "REQUEST FOR EXPEDITED TREATMENT AND FOR SHORTENED RESPONSE TIME TO FIVE BUSINESS DAYS, PURSUANT TO RULE 3614(f)." The movant shall concurrently provide an electronic copy of the motion to the utility. Response time to any such motion is automatically shortened to five business days.

3615. Exemptions and Exclusions.

(a) The following resources need not be included in an approved resource plan prior to acquisition.

(I) Emergency maintenance or repairs made to utility-owned generation facilities.

(II) Capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 30 MW.

(III) Capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two year term (including renewal terms) or for not more than 30 MW of capacity.

(IV) Improvements or modifications to existing utility generation facilities that change the production capability of the generation facility site in question, by not more than 30 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million.

(V) Interruptible service provided to the utility's electric customers.

(VI) Modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 30 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

(VII) Utility investments in emission control equipment at existing generation plants.

(VIII) Utility administered demand-side programs implemented in accordance with § 40-3.2-104, C.R.S.

(b) If the utility evaluates an existing or proposed electric generation facility offered in a competitive bidding process conducted outside of an approved resource plan, the utility shall provide the owner or developer of the electric generation facility in writing by e-mail the modeling inputs and assumptions that reasonably relate to the facility or to the transmission of electricity from that facility to the utility within 14 calendar days of the utility's decision to advance the potential resource to computer-based modeling.

3616. Request(s) For Proposals.

(a) Purpose of the request(s) for proposals. The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire additional resources pursuant to rule 3611. To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract to match each type of resource need, including contracts for supply-side resources, energy storage systems, renewable energy resources, or Section 123 resources as required by the approved resource plan.

(b) Contents of the request(s) for proposals. The proposed RFP(s) shall include the bid evaluation criteria the utility plans to use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas pursuant to rule 3608, including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; any physical and performance requirements for energy storage systems or instructions for bidders to explain characteristics of energy storage systems, including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations; and methodologies or credit mechanisms to value energy storage services provided to the utility system; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(c) Employment metrics. The utility shall request from bidders the following information relating to best value employment metrics for each bid resource:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

(d) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility pursuant to paragraph 3613(b). The utility shall also provide potential bidders with an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to paragraph 3613(b).

(e) The utility shall require bidders to provide the contact name of the owner or developer designated to receive notice pursuant to paragraph 3613(a).

(f) The utility shall inform bidders that certain bid information submitted in response to the RFP will be made available to the public through the posting of certain bid information on the utility's website upon the completion of the competitive acquisition process pursuant to paragraph 3613(k).

3617. Commission Review and Approval of Resource Plans.

(a) Review on the merits. The utility's plan, as developed pursuant to rule 3604, shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure. The Commission may hold a hearing for the purpose of reviewing, and rendering a decision regarding, the contents of the utility's filed resource plan.

(b) Basis for Commission decision. Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's plan filed in accordance with rule 3604. If the Commission declines to approve a plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 60 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

(c) Contents of the Commission decision. The Commission decision approving or denying the plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and, the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, energy storage systems, or Section 123 resources. A Commission decision pursuant to paragraph 3613(h) shall become part of the decision approving or modifying a utility's plan developed under rule 3604.

(d) Effect of the Commission decision. A Commission decision specifically approving the components of a utility's plan creates a presumption that utility actions consistent with that approval are prudent.

(I) In a proceeding concerning the utility's request to recover the investments or expenses associated with new resources.

(A) The utility must present prima facie evidence that its actions were consistent with Commission decisions specifically approving or modifying components of the plan.

(B) To support a Commission decision to disallow investments or expenses associated with new resources on the grounds that the utility's actions were not consistent with a Commission approved plan, an intervenor must present evidence to overcome the utility's prima facie evidence that its actions were consistent with Commission decisions approving or modifying components of the plan. Alternatively, an intervenor may present evidence that, due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper.

(II) In a proceeding concerning the utility's request for a CPCN to meet customer need specifically approved by the Commission in its decision on the final cost-effective resource plan, the Commission shall take administrative notice of its decision on the plan. Any party challenging the Commission's decision regarding need for additional resources has the burden of proving that, due to a change in circumstances, the Commission's decision on need is no longer valid.

3618. Reports.

(a) Annual progress reports. The utility shall file with the Commission, and shall provide to all parties to the most recent resource planning proceeding, annual progress reports after submission of its plan application. The annual progress reports will inform the Commission of the utility's efforts under the approved plan and the emerging resource needs and potential utility proposals that may be part of the utility's next electric resource plan filing. Annual progress reports shall contain the following, for a running ten-year period beginning at the report date:

(I) an updated annual electric demand and energy forecast developed pursuant to rule 3606;

(II) an updated evaluation of existing resources developed pursuant to rule 3607;

(III) an updated evaluation of planning reserve margins and contingency plans developed pursuant to rule 3609;

(IV) an updated assessment of need for additional resources developed pursuant to rule 3610;

(V) an updated report of the utility's plan to meet the resource need developed pursuant to rule 3611 and the resources the utility has acquired to date in implementation of the plan; and

(VI) in addition to the items required in subparagraphs(a)(I) through (a)(V), a cooperative electric generation and transmission association shall include in its annual report a full explanation of how its future resource acquisition plans will give fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(b) Reports of the competitive acquisition process. The utility shall provide reports to the Commission concerning the progress and results of the competitive acquisition of resources. The following reports shall be filed:

(I) Within 30 days after bids are received in response to the RFP(s), the utility shall report: the identity of the bidders and the number of bids received; the quantity of MW offered by bidders; a breakdown of the number of bids and MW received by resource type; and, a description of the prices of the resources offered.

(II) If, upon examination of the bids, the utility determines that the proposed resources may not meet the utility's expected resource needs, the utility shall file, within 30 days after bids are received, an application for approval of a contingency plan. The application shall include the information required by paragraphs 3002(b) and 3002(c), the justification for need of the contingency plan, the proposed action by the utility, the expected costs, and the expected timeframe for implementation.

3619. Amendment of an Approved Plan.

The utility may file, at any time, an application to amend the contents of a plan approved pursuant to rule 3617. Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

3620. – 3624. [Reserved]

TRANSMISSION PLANNING

3625. Applicability.

This rule shall apply to all electric utilities in the state of Colorado except municipally owned utilities and cooperative electric associations that have voted to exempt themselves from regulation pursuant to § 40 9.5-103, C.R.S.

3626. Overview and Purpose.

The purpose of these rules is to establish a process to coordinate the planning for additional electric transmission in Colorado. The Commission endorses the concept that planning should be done on a comprehensive, transparent, state-wide basis and should take into account the needs of all stakeholders.

3627. Transmission Planning.

(a) No later than February 1 of each even year, each electric utility shall file a ten-year transmission plan and supporting documentation pursuant to this rule.

(I) Each ten-year transmission plan shall meet the following goals:

(A) the proposed projects do not negatively impact the system of any other transmission provider or the overall transmission system in the near-term and long-term planning horizons;

(B) the proposed projects avoid duplication of facilities;

(C) the proposed projects reflect the development of joint projects where a proposed project services the mutual needs of more than one transmission provider and/or stakeholder; and

(D) the proposed projects are coordinated with all transmission providers in Colorado.

(II) The plan shall identify all proposed facilities 100kV or greater.

(III) If any of the information required to be filed pursuant to this rule is available on a utility or utility maintained website, then it is sufficient for purposes of this rule to include in the filing a web address that provides direct access to that specific piece of information. This address must remain active until the next biennial filing.

(b) Each ten-year transmission plan shall demonstrate compliance with the following requirements:

(I) The efficient utilization of the transmission system on a best-cost basis, considering both the short-term and long-term needs of the system. The best-cost is defined as balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost.

(II) All applicable reliability criteria for selected demand levels over a range of forecast system demands, including summer peak load, winter peak load and reduced load when renewable generation is maximized.

(III) All legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements.

(IV) Consistency with applicable transmission planning requirements in the FERC Order 890.

(c) Each ten-year transmission plan shall contain the following information.

(I) The methodology, criteria and assumptions used to develop the transmission plan. This includes the transmission facility rating methodology and established facility ratings; transmission base case data for all applicable power flows, short circuit and transient stability analyses; and utility specific reliability criteria.

(II) The load forecasts, load forecast reductions arising from net metered distributed generation and utility sponsored energy efficiency programs, and controllable demand - side management data including the interruptible demands and direct load control management used to develop the transmission plan.

(III) The generation assumptions and data used to develop the transmission plan.

(IV) The methodology used to determine system operating limits, transfer capabilities, capacity benefit margin, and transmission reliability margin, with supporting data and corresponding established values.

(V) The status of upgrades identified in the transmission plan, as well as changes, additions or deletions in the current plan when compared with the prior plan.

(VI) The related studies and reports for each new transmission facility identified in the transmission plan including alternatives considered and the rationale for choosing the preferred alternative. The depth of the studies, reports, and consideration of alternatives shall be commensurate with the nature and timing of the new transmission facility.

(VII) The expected in-service date for the facilities identified in the transmission plan and the entities responsible for constructing and financing each facility.

(VIII) A summary of stakeholder participation and input and how this input was incorporated in the transmission plan.

(IX) Each electric utility subject to rate regulation shall also include energy resource zone plans, designations, and applications for certificates of public convenience and necessity pursuant to § 40-2-126(2), C.R.S.

(d) No later than February 1 of each even year, each utility shall file all economic studies performed pursuant to FERC Order 890 since the last biennial filing. Such studies generally evaluate whether transmission upgrades or other investments can reduce the overall costs of serving native load. These studies are conducted for the purpose of planning for the alleviation of transmission bottlenecks or expanding the transmission system in a manner that can benefit large numbers of customers, such as the evaluation of transmission upgrades or additions necessary to build or acquire new generation resources. The report shall identify who requested the economic study and shall identify all economic studies requested but not performed.

(e) No later than February 1 of each even year, each utility shall file conceptual long-range scenarios that look 20 years into the future. These conceptual long-range scenarios shall analyze projected system needs for various credible alternatives, including, at a minimum, the following:

(I) reasonably foreseeable future public policy initiatives;

(II) possible retirement of existing generation due to age, environmental regulations or economic considerations;

(III) emerging generation, transmission and demand limiting technologies;

(IV) various load growth projections; and

(V) studies of any scenarios requested by the Commission in the previous biennial review process.

(f) Amended filings made pursuant to this rule are permitted at any time for good cause shown.

(g) Government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process.

(I) Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process.

(II) During the development of the ten-year transmission plan when objectives and needs are being identified, each utility shall actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions.

(III) Once a utility has evaluated the alternative solutions and has prepared recommendations for inclusion in its ten-year transmission plan, the utility shall notify the government agencies and stakeholders of these recommendations.

(IV) The outreach anticipated in subparagraphs (g)(II) and (g)(III) shall occur in a timely manner prior to the filing of the ten-year plans.

(V) Each utility shall concurrently provide the filings made pursuant to this rule to all government agencies and other stakeholders that participate in the planning process.

(h) After the ten-year transmission plans have been filed by utilities, the Commission will consolidate the plans in one proceeding. In this proceeding, the Commission will solicit written comments and will hold a workshop(s) and/or a hearing(s) on the plans for the purpose of reviewing and rendering a decision regarding the adequacy of the utilities' filed transmission plans and process used in formulating the plans. The Commission, on its own motion or at the request of others, may request additional supporting information from the utilities or the commenters. The Commission will review the plans and supporting information, the written comments, and the information obtained at the workshop(s) or hearing(s), and will issue a written decision regarding compliance with these rules and the adequacy of the existing and planned transmission facilities in this state to meet the present and future energy needs in a reliable manner. In this decision, the Commission may also provide further guidance to be used in the preparation of the next biennial filing.

(i) Utilities shall make reference to the most recently filed ten-year transmission plan in any subsequent CPCN application for individual projects contained in that plan. Given sufficient documentation in the biennial ten-year transmission plan for the project under review and if circumstances for the project have not changed, the applicant may rely substantively on the information contained in the plan and the Commission's decision on the review of the plan to support its application. The Commission will take administrative notice of its decision on the plan. Any party challenging the need for the requested transmission project has the burden of proving that, due to a change in circumstances, the Commission's decision is no longer applicable or valid.

3628. – 3649. [Reserved]

RENEWABLE ENERGY STANDARD

3650. Applicability.

(a) Rules 3650 through 3668 shall apply to all investor owned jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority.

(b) Rules 3651, 3652, 3654(b), (d) through (i), and (l), 3659(a)(I) through (a)(V), (b), (d) through (i), 3660(l), 3661(b), (c), (g),and (i), 3662(a)(I), (a)(II), (a)(IV) through (a)(X), (a)(XIII), (a)(XV), (b), (d) and (e), and 3667 shall apply to cooperative electric associations in the state of Colorado.

(c) Rules 3651, 3652, 3653, 3654(b), (c), (d) through (i) and (l), 3659(a)(I) through (a)(V), (b), (d) through (i) shall apply to municipally owned electric utilities in the state of Colorado, which are QRUs.

(d) The board of directors of each municipally owned electric utility not subject to these rules may, at its option, submit the question of whether to be subject to these rules to its consumers on a one meter equals one vote basis. Approval by a majority of those voting in the election shall be required for such inclusion, providing that a minimum of 25 percent of eligible consumers participates in the election.

(I) Within 45 days of the conclusion of any vote to be subject to these rules, the municipally owned electric utility shall provide written notification of the outcome of the vote to the Director of the Commission.

(e) Rules 3650, 3651, 3652, 3662(f), and 3668(d) shall apply to cooperative electric generation and transmission associations.

(f) Nothing in these rules is intended to expand the Commission's regulatory oversight and powers over municipally owned electric utilities, cooperative electric associations, or cooperative electric generation and transmission associations.

3651. Overview and Purpose.

The purpose of these rules is to establish a process to implement the RES for qualifying retail utilities in Colorado, pursuant to §§ 40-2-124 and 40-2-127, C.R.S.

Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.

Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent.

It is the policy of this State to encourage local ownership of renewable energy generation facilities to improve the financial stability of rural communities.

3652. Definitions.

The following definitions apply only to rules 3650 – 3668. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Annual compliance report" means the report a QRU is required to file annually with the Commission pursuant to rule 3662 to demonstrate compliance with the RES.

(b) "Biomass" means nontoxic plant matter consisting of agricultural crops or their byproducts, urban wood waste, mill residue, slash, or brush; animal wastes and products of animal wastes; or methane produced at landfills or as a by-product of the treatment of wastewater residuals. With respect to nontoxic plant matter obtained from forests, both slash and brush shall mean products and materials derived from forest restoration and management, including, but not limited to, harvesting residues, pre-commercial thinning, and materials removed as part of a federally recognized timber sale or removed to reduce hazardous fuels, to reduce or contain disease or insect infestation, or to restore ecosystem health.

(c) "Coal mine methane" means methane captured from inactive coal mines where the methane is escaping to the atmosphere or from active coal mines where the methane vented in the normal course of mine operations is naturally escaping to the atmosphere.

(d) "Community-based project" means a project that meets the following three conditions: the project is owned by individual residents of a community, by an organization or cooperative that is controlled by individual residents of the community, by a local government entity, or by a tribal council; the project's generating capacity does not exceed 30 MW; and, there exists a resolution of support adopted by the local governing body of each local jurisdiction in which the project is to be located.

(e) "Community solar garden" or "CSG" means a solar electric generation facility with a nameplate rating of two MW or less that is located in or near a community served by a QRU where the beneficial use of the renewable energy generated by the facility belongs to the subscribers of the CSG. A CSG shall have at least ten CSG subscribers. A CSG shall be deemed to be located on the site of each subscribing customer's facilities for the purpose of crediting the CSG subscribers' bills for the renewable energy purchased from the CSG by the QRU. The renewable energy generated by a CSG shall be sold only to the QRU serving the geographic area where the CSG is located. The renewable energy generated by a CSG shall constitute retail renewable distributed generation under paragraph 3652(ff).

(f) "Compliance plan" means the annual plan a QRU is required to file with the Commission pursuant to rule 3657.

(g) "Compliance year" means a calendar year for which the RES is applicable.

(h) "CSG owner" means the owner of the solar generation facilities installed at a CSG that contracts to sell the unsubscribed renewable energy and RECs generated by the CSG to a QRU. A CSG subscriber organization operating a CSG not owned by it will be deemed to be a CSG owner for purposes of these rules. A CSG owner may be the QRU or any other for-profit or nonprofit entity or organization, including a CSG subscriber organization.

(i) "CSG subscriber" means a retail customer of a QRU who owns a subscription to a CSG and who has identified one or more premises served by the QRU to which the CSG subscription shall be attributed.

(j) "CSG subscriber organization" means any for-profit or nonprofit entity permitted by Colorado law and whose sole purpose shall be:

(I) to beneficially own and operate the CSG; or

(II) to operate the CSG that is built, owned, and operated by a third party under contract with such CSG subscriber organization.

(k) "CSG subscription" means a proportionate interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG.

(l) "Early eligible energy resources" are eligible energy resources, excluding retail renewable distributed generation, where the utility certifies that the resource is commercially operational and can produce energy under the terms of its contract, prior to January 1, 2015.

(m) "Eligible energy" means renewable energy, recycled energy, or greenhouse gas neutral electricity generated by a facility using coal mine methane or synthetic gas.

(n) "Eligible energy resources" are renewable energy resources or facilities that generate recycled energy or greenhouse gas neutral electricity generated using coal mine methane or synthetic gas.

(o) "Eligible low-income CSG subscriber" means a residential customer of an investor owned QRU who:

(I) has a household income at or below 165 percent of the current federal poverty level, as published each year in the federal register by the U.S. Department of Health and Human Services; and

(II) otherwise meets the eligibility criteria set forth in rules of the Colorado Department of Human Services adopted pursuant to § 40-8.5-105, C.R.S.

(p) "Greenhouse gas neutral electricity" means electricity generated by facilities using coal mine methane or synthetic gas that the Commission has determined to be greenhouse gas neutral on a CO_2 equivalent basis pursuant to § 40-2-124(1)(a)(IV), C.R.S.

(q) "On-site solar system" means a solar renewable energy system that is retail renewable distributed generation.

(r) "Person" means Commission staff or any individual, firm, partnership, corporation, company, association, cooperative association, joint stock association, joint venture, governmental entity, or other legal entity.

(s) "Pyrolysis" means the thermochemical decomposition of material at elevated temperatures without the participation of oxygen.

(t) "Qualifying retail utility" or "QRU" means any provider of retail electric service in the state of Colorado other than municipally owned electric utilities that serve 40,000 customers or fewer.

(u) "Qualifying wholesale utility" means a generation and transmission cooperative electric association that provides wholesale electric service directly to Colorado cooperative electric associations that are its members.

(v) "Recycled energy" means energy produced by a generation unit with a nameplate capacity of not more than fifteen MW that converts the otherwise lost energy from the heat from exhaust stacks or pipes to electricity and that does not combust additional fossil fuel. Recycled energy does not include energy produced by any system that uses energy, lost or otherwise, from a process whose primary purpose is the generation of electricity, including, without limitation, any process involving engine-driven generation or pumped hydroelectricity generation.

(w) "Renewable distributed generation" means retail renewable distributed generation and wholesale renewable distributed generation.

(x) "Renewable energy" means energy generated from renewable energy resources including renewable distributed generation.

(y) "Renewable energy credit" or "REC" means a contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly attributable to a specific amount of electric energy generated from a renewable energy resource. One REC results from one MWH of electric energy generated from a renewable energy resource. For the purposes of these rules, RECs acquired from on-site solar systems before August 11, 2010 shall qualify as RECs from retail renewable distributed generation for purposes of demonstrating compliance with the renewable energy standard. RECs acquired from off-grid on-site solar systems prior to August 11, 2010 shall also qualify as RECs from retail renewable distributed generation for purposes of demonstrating compliance with the renewable energy standard.

(z) "Renewable energy credit contract" means a contract for the sale of renewable energy credits without the associated energy.

(aa) "Renewable energy resource" means facilities that generate electricity by means of the following energy sources: solar radiation, wind, geothermal, biomass, hydropower, and fuel cells using hydrogen derived from eligible energy resources. Fossil and nuclear fuels and their derivatives are not eligible energy resources. Hydropower resources in existence on January 1, 2005 must have a nameplate rating of 30 MW or less. Hydropower resources not in existence on January 1, 2005 must have a nameplate rating of ten MW or less.

(bb) "Renewable energy standard" or "RES" means the electric resource standard for eligible energy resources specified in § 40-2-124, C.R.S.

(cc) "Renewable energy standard adjustment" or "RESA" means a forward-looking cost recovery mechanism used by an investor owned QRU to provide funding for implementing the RES.

(dd) "Renewable energy supply contract" means a contract for the sale of renewable energy and the RECs associated with such renewable energy. If the contract is silent as to renewable energy credits, the renewable energy credits will be deemed to be combined with the energy transferred under the contract.

(ee) "Retail electricity sales" means electric energy sold to retail end-use electric consumers by a QRU or an electric utility that is eligible to become a QRU pursuant to § 40-2-124(5)(b), C.R.S,

(ff) "Retail renewable distributed generation" means a renewable energy resource that is located on the premises of an end-use electric consumer and is interconnected on the end-use electric consumer's side of the meter. For the purposes of this definition, the non-residential end-use electric customer, prior to the installation of the renewable energy resource, shall not have its primary business being the generation of electricity for retail or wholesale sale from the same facility. In addition, at the time of the installation of the renewable energy resource, the non-residential end-use electric customer must use its existing facility for a legitimate commercial, industrial, governmental, or educational purpose other than the generation of electricity. Retail renewable distributed generation shall be sized to supply no more than 120 percent of the average annual consumption of electricity by the end-use electric consumer at that site. The end-use electric consumer's site shall include all contiguous property owned or leased by the consumer, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.

(gg) "Rural renewable project" means a renewable energy resource with a nameplate rating of 30 MW or less that interconnects to electric transmission or distribution facilities owned by a cooperative electric association or municipally owned utility at a point of interconnection of 69 kV or less.

(hh) "Service entrance capacity" means the capacity of the QRU's electric service conductors that are physically connected to the customer's electric service entrance conductors.

(ii) "Solar renewable energy system" means a system that uses solar radiation energy to generate electricity.

(jj) "Standard rebate offer" or "SRO" means a standardized incentive program offered by a QRU to its retail electric service customers for on-site solar systems as set forth in rule 3658.

(kk) "Synthetic gas" means gas fuel produced through the pyrolysis of municipal solid waste.

(ll) "Wholesale renewable distributed generation" means a renewable energy resource with a nameplate rating of 30 MW or less that does not qualify as retail renewable distributed generation.

3653. Municipal Utilities.

(a) Each municipally owned QRU implementing a RES substantially similar to the provisions of § 40-2-124, C.R.S., shall submit a statement to the Commission that demonstrates its RES program, at a minimum, meets the following criteria:

(I) the eligible energy resources shall be limited to those identified in subsection § 40-2-124(1)(a);

(II) the percentage requirements shall be equal to or greater in the same years than those identified in subsection § 40-2-124(1)(c)(V) and counted in the manner allowed by rule 3654; and

(III) the utility must have an optional pricing program in effect that allows retail customers the option to support through utility rates emerging renewable energy technologies.

(b) The statement to be submitted by a municipally owned QRU is for information purposes only and is not subject to approval by the Commission. Upon filing of the certification statement, the municipally owned QRU shall have no further obligations under these rules.

(c) Nothing in this section prohibits a municipally owned electric utility from buying and selling RECs.

3654. Renewable Energy Standard.

(a) Each investor owned QRU shall generate or cause to be generated (through purchase or by providing rebates or other form of incentive) eligible energy, including the renewable distributed generation required under paragraphs 3655(a) and (b), in the following minimum amounts:

(I) twenty percent of its retail electricity sales in Colorado for each of the compliance years 2015 through 2019; and

(II) thirty percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(b) Each cooperative electric association QRU that serves fewer than 100,000 meters and municipally owned QRU shall generate or cause to be generated eligible energy in the following minimum amounts:

(I) six percent of its retail electricity sales in Colorado for each of the compliance years 2015 through 2019; and

(II) ten percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter

(c) Each cooperative electric association QRU that serves 100,000 or more meters shall generate or cause to be generated eligible energy in amounts that are at least 20 percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(d) For municipal utilities that become municipally owned QRUs after December 31, 2006, the minimum percentage requirements of eligible energy shall begin in the first calendar year following qualification as follows:

(I) years one through three: One percent of retail electricity sales;

(II) years four through seven: Three percent of retail electricity sales;

(III) years eight through twelve: Six percent of retail electricity sales; and

(IV) tears 13 and thereafter: Ten percent of retail electricity sales.

(e) For purposes of cooperative electric association QRU compliance with the RES specified in paragraphs 3654(b) and (c), each kWh of eligible energy generated from solar electric generation technology shall be counted as 3.0 kWh of eligible energy, provided that the solar electric generation technology commenced producing electricity prior to July 1, 2015. For solar electric generation technology that commenced producing electricity on or after July 1, 2015, each kWh of eligible energy generated from solar electric generation technology shall be counted as 1.0 kWh of eligible energy for compliance purposes.

(f) For purposes of municipally owned QRU compliance with the RES specified in paragraphs 3653(a) and 3654(d), each kWh of eligible energy generated from solar electric generation technology shall be counted as 3.0 kWh of eligible energy, provided that the solar electric generation technology was under contract for development prior to August 1, 2015 and commenced producing electricity prior to December 31, 2016. For solar electric generation technology that either was not under contract for development prior to August 1, 2015 or commenced producing electricity on or after December 31, 2016, each kWh of eligible energy generated from solar electric generation technology shall be counted as 1.0 kWh of eligible energy for compliance purposes.

(g) For purposes of compliance with the RES, each kWh of eligible energy generated by an early eligible energy resource shall be counted as 1.25 kWh of eligible energy. Eligible energy generated by retail renewable distributed generation for which a QRU has entered into a purchase transaction prior to August 11, 2010 shall also be counted as 1.25 kWh of eligible energy.

(h) For purposes of compliance with the RES, each kWh of eligible energy generated from a community-based project shall be counted as 1.5 kWh of eligible energy.

(i) For purposes of compliance with the RES, each kWh of eligible energy generated from a rural renewable project may be counted as two kWh of eligible energy subject to the restrictions on rural renewable projects in rule 3666.

(j) For purposes of compliance with the RES, each kWh of eligible energy shall be subject to only one of the compliance multipliers in paragraphs 3654(e), (f), (g) or (h).

(k) For purposes of compliance with the RES, a QRU may generate, or cause to be generated, and count eligible energy or RECs for compliance:

(I) For the compliance year immediately preceding the compliance year during which they were generated, provided that such eligible energy or RECs are generated no later than July 1 of the calendar year immediately following the end of the compliance year for which they are being counted;

(II) For the compliance year during which they were generated; or

(III) For the five compliance years immediately following the compliance year during which they were generated.

(l) For purposes of compliance with this RES, a QRU may substitute the equivalent RECs for eligible energy.

(m) For purposes of compliance with this RES, there shall be no “double counting” of eligible energy or RECs. RECs shall be used for a single purpose only, and shall be retired upon use for that purpose. Notwithstanding the foregoing, eligible energy and RECs generated or acquired by a QRU and counted toward compliance with a federal RES may also be counted by the QRU toward compliance with the state RES.

(n) RECs associated with eligible energy sold by the investor owned QRU under an optional renewable energy pricing program shall be retired by the investor owned QRU and may not be counted by the investor owned QRU toward compliance with the RES.

(o) For purposes of compliance with this RES, if a generation system uses a combination of fossil fuel and eligible energy resources to generate electricity, a QRU may count only as eligible energy the proportion of the total electric output of the generation system that results from the use of eligible energy resources. The QRU shall include in its annual compliance plan the method of calculation used to determine the proportion of eligible energy.

(p) The QRU may generate, or cause to be generated, eligible energy without regard to economic dispatch procedures.

(q) For the purpose of compliance with the RES, a QRU shall cause eligible energy to be generated through payment for the eligible energy by contract or tariff, through payment of a standard offer under Rule 3658, or through the payment of another incentive.

3655. Renewable Distributed Generation.

(a) In conjunction with the RES set forth in paragraph 3654(a), each investor owned QRU shall generate or cause to be generated (through purchase or by providing rebates or other form of incentive) renewable distributed generation in the following minimum amounts, unless the Commission amends such minimum amounts under paragraph 3655(c):

(I) one and three-fourths percent of its retail electricity sales in Colorado for each of the compliance years 2015 through 2016;

(II) two percent of its retail electricity sales in Colorado for each of the compliance years 2017 through 2019; and

(III) three percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(b) Of the amounts of renewable distributed generation set forth in paragraph 3655(a), at least one-half shall be derived from retail renewable distributed generation unless modified by the Commission under paragraph 3655(c).

(c) The Commission may change the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation set forth in paragraphs 3655(a) and (b) pursuant to a filing under paragraph 3657(a). The Commission may reduce the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation set forth in paragraphs 3655(a) and (b) for effect after December 31, 2014 upon finding that those minimum amounts are no longer in the public interest. In the event that the Commission finds that the public interest requires an increase in such minimum amounts after December 31, 2014, the Commission shall report such findings to the Colorado General Assembly.

(d) The investor owned QRU may propose in a compliance plan filing under rule 3657, or by a separate application, that the Commission reduce the percentages set forth in paragraph 3655(a) and (b).

(e) Renewable energy credits associated with retail renewable distributed generation and wholesale renewable distributed generation will be used to comply with the renewable distributed generation requirements as set forth in this rule 3655. Eligible energy and RECs produced by renewable distributed generation shall be governed by rules 3654 and 3659, unless otherwise exempt from those provisions.

(f) In a final decision concerning the investor owned QRU's compliance plan, as between residential and nonresidential retail renewable distributed generation, the Commission shall direct the investor owned QRU to allocate its expenditures for the acquisition of retail renewable distributed generation according to the proportion of RESA revenues derived from each of these customer groups; except that the investor owned QRU may acquire retail renewable distribution generation at levels that differ from these group allocations based upon market response to the QRU's programs.

(g) RECs generated from CSGs shall not be used to achieve more than 20 percent of the retail renewable distributed generation requirements as set forth in paragraph 3655(a) for compliance years 2011, 2012, and 2013.

(h) In conjunction with the RES set forth in subparagraph 3654(b)(IV), each cooperative electric association QRU that serves 10,000 or more meters but less than 100,000 meters shall generate or cause to be generated renewable distributed generation in amounts that are at least one percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(i) In conjunction with the RES set forth in subparagraph 3654(b)(IV), each cooperative electric association QRU that serves fewer than 10,000 meters may generate or cause to be generated renewable distributed generation in amounts that are at least three-fourths percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(j) In conjunction with the RES set forth in paragraph 3654(c), each cooperative electric association QRU that serves 100,000 or more meters shall generate or cause to be generated renewable distributed generation in amounts that are at least one percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(k) For the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(h), 3665(i), and 3655(j), a cooperative electric association QRU may subtract industrial retail sales from total retail sales in calculating its minimum retail renewable distributed generation requirement.

(l) For the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(h), 3655(i), and 3655(j), an electric generation facility constitutes retail renewable distributed generation if it: is a renewable energy resource; has a nameplate rating of two MW or less; is located within the service territory of the cooperative electric association; generates electricity for the beneficial use of subscribers who are members of the cooperative electric association; and has at least four subscribers if the facility has a nameplate rating of 50 KW or less and at least ten subscribers if the facility has a nameplate rating of more than 50 kW. A subscriber's share of the production from the facility may not exceed 120 percent of the subscriber's average annual electricity consumption at the premise to which the subscription is attributed. Each cooperative electric association may establish, in the manner it deems appropriate, the requirements and terms associated with the electric generation facilities: subscriber; subscription; pricing, including consideration of low-income members; metering; accounting; REC ownership; and other requirements and terms.

(m) Notwithstanding that rule 3665 does not apply to cooperative electric associations, a community solar garden constitutes retail renewable distributed generation for the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(h), 3655(i), and 3655(j).

3656. Resource Acquisition.

(a) It is the Commission's policy that utilities should meet the RES in the most cost-effective manner. To this end, the competitive acquisition provisions and exemptions of the Commission's Electric Resource Planning Rules shall apply to the acquisition of eligible energy resources by investor owned QRUs. Notwithstanding the exemptions in the Electric Resource Planning Rules, investor owned QRU shall acquire renewable distributed generation in accordance with a process set forth in a Commission-approved compliance plan or by separate application.

(b) When evaluating resource acquisitions to comply with the RES, the Commission shall consider, on a qualitative basis, factors that affect employment and the long-term economic viability of Colorado communities, including best value employment metrics.

(c) For new eligible energy resources that the investor owned QRU acquires from third-party suppliers, the investor owned QRU shall request from the suppliers and provide to the Commission the following best value employment metrics:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;

(II) the employment of Colorado workers as compared to importation of out-of-state workers;

(III) long-term career opportunities; and

(IV) industry-standard wages, health care, and pension benefits.

(d) In the event that an investor owned QRU proposes in a resource acquisition plan to construct a new eligible energy resource, the investor owned QRU shall provide the Commission with the same best value employment metrics as set forth in paragraph 3656(c).

(e) The investor owned QRU may apply to the Commission, at any time, for review and approval of renewable energy credit contracts of any size, and renewable energy supply contracts with renewable distributed generation. The Commission will review and rule on these contracts within 90 days of their filing. The Commission may set the contract for expedited hearing, if appropriate, under the Commission's Rules of Practice and Procedure. If the QRU enters into a renewable energy supply contract or a renewable energy credit contract in a form substantially similar to the form of contract approved by the Commission as part of the investor owned QRU's compliance plan, that contract shall be deemed approved by the Commission under this rule.

(f) Renewable energy supply contracts entered into after July 2, 2006:

(I) shall be for the acquisition of both renewable energy and the associated RECs;

(II) may reflect a fixed price, or a price that varies by year;

(III) shall have a minimum term of 20 years (or shorter at the sole discretion of the seller); and

(IV) shall require the seller to relinquish all REC ownership associated with contracted renewable energy to the buyer.

(g) Renewable energy credit contracts entered into after July 2, 2006:

(I) shall be for the acquisition of RECs only;

(II) may reflect a fixed price, or a price that varies by time period; and

(III) shall have a minimum term of 20 years if the REC is from an on-site solar system, except that such contracts for on-site solar systems of between 100 KW and one MW may have a different term if mutually agreed to by the parties.

(h) If the investor owned QRU intends to accept proposals as part of a competitive solicitation for eligible energy resources from the QRU or from an affiliate of the QRU, it shall include a written separation policy and name an independent auditor whom the utility proposes to hire to review and report to the Commission on the fairness of the competitive acquisition process. The independent auditor shall have at least five years' experience conducting and/or reviewing the conduct of competitive electric utility resource acquisition, including computerized portfolio costing analysis. The independent auditor shall be unaffiliated with the utility; and shall not, directly or indirectly, have benefited from employment or contracts with the utility in the preceding five years, except as an independent auditor under these rules. The independent auditor shall not participate in, or advise the utility with respect to, any decisions in the bid-solicitation or bid-evaluation process. The independent auditor shall conduct an audit of the utility's bid solicitation and evaluation process to determine whether it was conducted fairly. For purposes of such audit, the utility shall provide the independent auditor immediate and continuing access to all documents and data reviewed, used or produced by the utility in its bid solicitation and evaluation process. The utility shall make all its personnel, agents and contractors involved in the bid solicitation and evaluation available for interview by the auditor. The utility shall conduct any additional modeling requested by the independent auditor to test the assumptions and results of the bid evaluation analyses. Within 60 days of the utility's selection of final resources, the independent auditor shall file a report with the Commission containing the auditor's views on whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported. After the filing of the independent auditor's report, the utility, other bidders in the resource acquisition process and other interested parties shall be given the opportunity to review and comment on the independent auditor's report.

(i) Responses to competitive solicitations shall be evaluated and ranked by the investor owned QRU.

(I) In addition to the cost of the eligible energy and RECs, the QRU may take into consideration the characteristics of the underlying eligible energy resource that may impact the ability of the bidder to fulfill the terms of the bid including, but not limited to project in-service date, resource reliability, viability, energy security benefits, amount of water used, fuel cost savings, environmental impacts including tradable emissions allowances savings, load reduction during higher cost hours, transmission capacity and scheduling, employment, the long-term economic viability of Colorado communities, best value employment metrics, and any other factor the investor owned QRU determines is relevant to the investor owned QRU's needs.

(II) Bids with prices that vary by year will be evaluated by discounting the yearly prices at the utility discount rate.

(III) An investor owned QRU is not required to accept any bid and may reject any and all bids offered. However, each solicitation shall culminate in a report detailing the outcome of the solicitation and identifying which bids were selected, which were rejected, and why.

(IV) For purposes of comparing bids for RECs only with bids for electricity and RECs, the investor owned QRU shall assign a value for the electricity and subtract this value from the electricity and RECs bid, and evaluate bids on the basis of RECs only. The investor owned QRU shall include, as part of its compliance plan, a description of its methodology and price(s) it intends to use for this evaluation.

(j) Within 15 days of the due date for bids in a competitive solicitation, the investor owned QRU shall notify respondents as to whether their bid has met the bid submission criteria.

(k) Upon ranking of eligible bids to a competitive solicitation, each investor owned QRU shall within 15 days indicate to all respondents with which proposals it intends to pursue a contract.

(l) For eligible energy resources greater than 250 kW, the owner shall provide, at the QRU's request, real time electronic access to the QRU to system operation data. In the event that an eligible energy resource greater than 250 kW also collects meteorological data, the owner shall provide, at the QRU's request, real time electronic access to the QRU to such meteorological data.

3657. RES Compliance Plan.

(a) With each electric resource plan filed with the Commission under rule 3603 (every four years beginning October 31, 2015), the investor owned QRU shall file a RES compliance plan detailing how the QRU intends to comply with these rules during the resource acquisition period addressed in that rule 3603 filing. In addition to the required four-year cycle, the investor owned QRU may file an interim RES compliance plan by application at the Commission explaining the reasons and changed circumstances that justify the interim plan.

(b) Each investor owned QRU RES compliance plan shall include.

(I) Determination of the retail rate impact pursuant to rule 3661 and a presentation of projected RESA revenues, surcharges collected under paragraph 3664(h), expenditures, and deferred account balances (both positive and negative) over a minimum of ten years.

(II) For each eligible energy resource other than retail renewable distributed generation, a listing of each eligible energy resource whose on-going annual net incremental costs have been locked down and the value of the locked down on-going annual net incremental costs for each listed eligible energy resource. For retail renewable distributed generation, the QRU shall set forth this information in the aggregate, listed by the year in which the resources were acquired.

(III) For each eligible energy resource other than retail renewable distributed generation, a listing of the eligible energy resources whose on-going annual net incremental costs are expected to be locked down during the period covered by the compliance plan and the current projection of the locked down on-going annual net incremental costs for each listed eligible energy resource. For retail renewable distributed generation, the QRU shall set forth this information in the aggregate, listed by the year in which the resources were acquired.

(IV) Estimate of its retail electricity sales over a minimum of ten years.

(V) Estimate of the eligible energy and RECs that the QRU already has acquired and the QRU's estimate of the additional eligible energy and RECs that will be needed to meet both the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655.

(VI) Estimate of the funds that the QRU will have available to generate, or cause to be generated, additional eligible energy and RECs under the retail rate impact established in rule 3661, including, but not limited to, the RESA revenues collected from residential and nonresidential retail customers and other revenue resources.

(VII) Plan to acquire additional eligible energy and RECs given the constraints of the retail rate impact specified at rule 3661, including the allocation of the funds available under the retail rate impact rule to acquire eligible energy or RECs from each of the following: retail renewable distributed generation to be acquired under rule 3658 from residential retail customers; retail renewable distributed generation to be acquired under rule 3658 from nonresidential retail customers; wholesale renewable distributed generation; and eligible energy resources with nameplate ratings of more than 30 MW to be acquired pursuant to the Commission's Electric Resource Planning Rules.

(VIII) The standard offers the investor owned QRU intends to offer customers to purchase RECs from on-site solar systems that are no larger than 500 kW and a proposal, at the discretion of the QRU, to reduce the SRO based on market conditions.

(IX) Proposal, at the discretion of the investor owned QRU, to advance funds from year to year to augment the amounts collected from retail customers through the RESA for the acquisition of more eligible energy resources.

(X) Proposed request for proposals including any standard contracts the investor owned QRU plans to use as part of a competitive acquisition process.

(XI) Proposed ownership investment, if any, in eligible energy resources and estimate of whether its investment will provide net economic benefits to the QRU's customers, entitling the QRU to extra profit on its investment, pursuant to rule 3660.

(XII) Plan to purchase renewable energy and RECs from one or more CSGs over the period covered by the plan and subject to the requirements of rule 3665.

(XIII) Plan to encourage eligible low-income customer subscriptions in CSGs pursuant to subparagraph 3665(d)(V).

(XIV) The acquisition process for eligible energy resources, pursuant to rule 3656.

(XV) The treatment, tracking, counting and trading of RECs, pursuant to rule 3659.

(XVI) Rules, regulations, and tariffs for the net metering for renewable energy resources, pursuant to rule 3664.

(XVII) Application forms, standard agreements, and general procedures for the investor owned QRU's SRO programs under rule 3658 and for the interconnection of renewable energy resources pursuant to rule 3667.

(c) The Commission shall either approve the investor owned QRU's RES compliance plan or order modifications to the compliance plan. Investor owned QRU actions under an approved compliance plan shall carry a rebuttable presumption of prudence.

(d) The investor owned QRU may apply to the Commission at any time for approval of amendments to an approved RES compliance plan.

3658. Standard Rebate Offer.

(a) Each investor owned QRU shall make available to its retail electricity customers a standard rebate offer (SRO) expressed in terms of dollars per watt for on-site solar systems that become operational on or after December 1, 2004. The SRO shall be $2.00 per watt except that the Commission may set the SRO at a lower amount upon finding that market changes support such lower amount.

(b) The maximum rebate per site shall be 100 kW times the SRO. At the investor owned QRU's option, the SRO may be paid based upon the direct current (DC) watts produced by the on-site solar systems. The SRO shall be contingent upon the transfer to the investor owned QRU of the RECs produced by the on-site solar system. Any RECs acquired by the investor owned QRU pursuant to such SRO program, regardless of whether the associated renewable energy is specifically metered or contractually specified without specific metering, may be counted by the investor owned QRU for purposes of compliance with the RES.

(c) When establishing an SRO below $2.00 per watt, the Commission shall target an amount such that the SRO, in combination with the investor owned QRU's standard offers to purchase RECs from on-site solar systems and with other financial incentives and tax benefits, results in reasonable overall levels of incentives to the customers participating in the investor owned QRU's SRO programs.

(d) With each compliance plan filed by the investor owned QRU under rule 3657, or by separate application, the investor owned QRU may propose that the Commission reduce the SRO in accordance with projected changes in the standard prices the investor owned QRU offers customers for RECs from on-site solar systems.

(e) Investor owned QRUs may establish one or more standard offers to purchase RECs from on-site solar systems that meet the definition of paragraph 3652(ff) so long as the on-site solar system is 500 kW or less in size. Subject to the retail rate impact in rule 3661:

(I) the investor owned QRU shall design standard offers that allow consumers of all income levels to obtain the benefits offered by on-site solar systems and that extend participation to consumers in all market segments eligible for SRO programs; and

(II) the QRU shall have the discretion to determine, in a nondiscriminatory manner, the price it will pay for RECs from on-site solar systems that are no larger than 500 kW.

(f) The SRO and the standard offers to purchase RECs from on-site solar systems shall meet the following requirements.

(I) The investor owned QRU need not offer a SRO for or purchase RECs from an on-site solar system smaller than 500 watts.

(II) The SRO and the standard offer to purchase RECs must be made available to all retail utility customers of the investor owned QRU on a non-discriminatory, first-come, first-served basis, based upon the date of contract execution.

(III) Applicants who are accepted for the SRO rebates shall have one year from the date of contract execution to demonstrate substantial completion of their proposed on-site solar system. Substantial completion means the purchase and installation on the customer's premises of all major system components of the on-site solar system. Customers who do not achieve substantial completion within one year will not receive an SRO rebate, unless the substantial completion date is extended. When substantial completion of an on-site solar system has been achieved by an applicant pursuant to this rule, the RECs may be counted for purposes of compliance with the RES. Within 30 days of substantial completion, the SRO rebate, pursuant to paragraphs 3658(a) and (b), and REC payment, pursuant to subparagraph 3658(f)(VIII), shall be paid to the applicant.

(IV) With the exception of batteries, all on-site solar systems eligible for SRO rebates shall be covered by a minimum five-year warranty. Contracts will require customers to maintain the on-site solar system so that it remains operational for the term of the contract.

(V) On-site solar systems must consist of equipment that is commercially available and factory new when installed on the original customer's premises to be eligible for the SRO rebate. Rebuilt, used, or refurbished equipment is not eligible to receive the rebate unless the equipment is transferred by a commercial tenant from another premise as permitted by subparagraph 3658(f)(VII)(C).

(VI) Customers may contract to expand their on-site solar systems within program parameters and obtain a rebate for the expanded capacity up to the cap set forth in paragraph 3658(b).

(VII) In order to receive the SRO rebate payment

(A) A residential customer must enter into an agreement with the investor owned QRU, which agreement shall have a minimum term of 20 years and that transfers the RECs generated by the on-site solar system during the term of the agreement from the customer to the investor owned QRU.

(B) A commercial customer may enter into an agreement with the investor owned QRU, with a minimum term of 20 years, that transfers the RECs generated by the on-site solar system during the term of the agreement from the customer to the investor owned QRU; provided, however, that if the agreement is different than 20 years as permitted by subparagraph 3656(f)(III) the rebate shall be prorated to reflect the different term.

(C) Irrespective of the term of the REC transfer agreement between the commercial customer and the investor owned QRU, if the commercial customer is in a leased facility, the commercial customer must obtain the approval of the investor owned QRU, which shall not be unreasonably conditioned, delayed or withheld, and either permission from the commercial customer's landlord, or other documentation evidencing the tenant's unequivocal right to install an on-site solar system. Such commercial tenant customer may relocate the on-site solar system to a substitute premise reasonably acceptable to the investor owned QRU at any time during the term of the agreement, provided that:

(i) payment for all RECs shall be made by the investor owned QRU on a metered basis;

(ii) the new location is within the investor owned QRU's service territory;

(iii) the on-site solar system is not out of operation for more than 90 days due to such relocation;

(iv) the agreement is extended for the period of time the on-site solar system is out of operation; and

(v) the customer bears the cost of relocating the production meter, or the costs of setting a new production meter, at the new location.

(D) If the on-site solar system of a commercial customer is out of operation for more than 90 days, the investor owned QRU may terminate the agreement and upon such termination the customer must repay the pro rata share of the rebate based on the number of years remaining in the term of the agreement.

(VIII) Except for on-site solar systems of commercial tenants who opt for an agreement under subparagraph 3658(f)(VII)(C), and except for solar facilities that are owned by entities other than the on-site consumer of the solar energy, for on-site solar systems, up to and including ten kW, that become operational on or after December 1, 2004, the investor owned QRU shall offer to make a one-time payment, in addition to the standard rebate payment, for the RECs contracted to be transferred from the customer to the investor owned QRU. Any customer that receives the rebate payment and one-time REC payment under this program shall not be entitled to any other compensation for the RECs contracted to be transferred to the investor owned QRU. To facilitate installation of these small systems, all procedures, forms, and requirements shall be clear, simple, and straightforward to minimize the time and effort of homeowners and small businesses.

(IX) For on-site solar systems greater than ten kW that become operational on or after December 1, 2004, and for all on-site solar systems of whatever size that are owned by an entity other than the on-site consumer of the solar energy, the investor owned QRU, in addition to the standard rebate payment, shall offer to pay for the RECs contracted to be transferred from the customer to the investor owned QRU. Such SO-RECs and the associated payments shall be determined by the specifically metered renewable energy output from the on-site solar system.

(X) The customer or its representative shall provide a calculation of the annual expected kWh production from the customer's on-site solar system. The customer or its representative shall provide the following documentation to back up the customer's calculation:

(A) Tilt of the system in degrees (horizontal = 0 degrees);

(B) Orientation of the system in degrees (south = 180 degrees);

(C) A representation that the orientation of the system is free of trees, buildings and or other obstructions that might shade the system measured from the center point of the solar array through a horizontal angle plus or minus 60 degrees and a through vertical angle between 15 degrees and 90 degrees above the horizontal plane.

(D) A calculation of the annual expected kWh of electricity produced by the system. For PV systems, the calculation of annual expected kWh of electricity will be based on the public domain solar calculator PVWatts Version 1 (or equivalent upgrade).

(i) The weather station that is either nearest to or most similar in weather to the installation site;

(ii) The system output rating which equals the module rating times the inverter efficiency times the number of modules;

(iii) Array type: fixed tilt, single axis tracking, or 2 axis tracking; For variable tilt systems, the PVWatts calculations can be run multiple times corresponding to the number of times per year that the system tilt is expected to be changed using those months corresponding to the specific tilt angle used;

(iv) Array tilt (degrees); and

(v) Array azimuth (degrees).

(E) In the event PVWatts is no longer available, an equivalent tool shall be established.

(F) For on-site solar systems up to and including ten kW, the REC payment may be adjusted, either up or down, based on the calculation of expected kWh of electric output derived from subparagraph 3658(f)(X)(D) as compared with an optimally oriented fixed, i.e., non-tracking, system at the customer's location, but only if the calculated system output differs from the optimally oriented system output by more than ten percent.

(XI) The level of REC payments for systems of ten kW and smaller offered in connection with an investor owned QRU's SRO program may be adjusted from time to time as needed to achieve compliance with the RES.

(XII) Except for on-site solar systems of commercial tenants who opt for an agreement under subparagraph 3658(f)(VII)(C), the on-site solar system installed must remain in place on the customer's premises for the duration of its contract life. However, all customer equipment must have electrical connections in accordance with industry practice for permanently installed equipment, and it must be secured to a permanent surface (*e.g.*, foundation, roof, etc.). Any indication of portability, including, but not limited to, wheels, carrying handles, dolly, trailer or platform, will render any on-site solar system ineligible for participation and payments under the SRO program.

(XIII) On-site solar systems installed on an apartment building must either be owned and operated by the owner of the building or the owner of the facility must provide documentation of the right to install and maintain the solar panels on the apartment building premises for 20 years. Each on-site solar system must be dedicated to a specific meter and the load at the meter must meet the size limits for net metering of on-site solar systems.

(XIV) On-site solar systems installed on condominiums must be owned by the condominium owner, or by a third party on behalf of the condominium owner, and metered to that owner’s unit. The owner must provide documentation that the owner has the legal right to install and maintain the solar panels at the site for the term of the 20-year agreement. If the on-site solar system serves a general common element common area, the contract will be with the condominium owners’ association. If the on-site solar system serves a limited common element common area, the contract will be with the condominium unit owner or owners.

(g) The investor owned QRU shall modify the standard contracts for its SRO programs to enable governmental entities to participate in such programs.

(h) Sales of electricity may be made by an owner or operator of an on-site solar system to the end-use electric consumer located at the site of the on-site solar system. If the on-site solar system is not owned by the electric consumer, the investor owned QRU shall pay for the RECs on a metered basis. The owner or operator of the on-site solar system shall pay the cost of installing the production meter.

3659. Renewable Energy Credits.

(a) Renewable energy credits may be used to comply with the RES and may include:

(I) RECs generated by renewable energy resources owned by the QRU or by a QRU affiliate;

(II) RECs acquired by the QRU pursuant to renewable energy supply contracts;

(III) RECs acquired by the QRU pursuant to renewable energy credit contracts;

(IV) RECs acquired by the QRU pursuant to a standard offer program;

(V) RECs acquired through a system of tradable renewable energy credits, from exchanges or from brokers

(VI) RECs carried forward from previous compliance years, pursuant to rule 3654; and

(VII) RECs borrowed forward from future compliance years, pursuant to rule 3654.

(b) RECs representing electricity generated at renewable energy resources shall be counted for compliance purposes consistent with the compliance multipliers in paragraphs 3654(e), (f), (g), or (h).

(c) The Commission shall not restrict the investor owned QRU's ownership of RECs if the investor owned QRU complies with both the RES established in rule 3654 and the requirements for renewable distributed generation established in rule 3655 and if the investor owned QRU complies with the retail rate impact established in rule 3661.

(d) All contracts between QRUs and the owners of renewable energy resources entered into after the effective day of these rules shall clearly specify the entity who shall own the RECs associated with the energy generated by the facility.

(e) A REC shall expire at the end of the fifth calendar year following the calendar year during which it was generated.

(f) RECs shall be used for a single purpose only, and shall expire or be retired upon use for that purpose. All RECs utilized by the QRU to comply with the RES:

(I) may not be sold or otherwise exchanged with any other party, or in any other state or jurisdiction;

(II) may not be included within a blended energy product certified to include a fixed percentage of renewable energy in any other state or jurisdiction; and

(III) may be counted simultaneously toward compliance with a federal renewable portfolio standard and with the RES.

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

(h) If a renewable energy system uses a renewable energy resource in combination with a nonrenewable energy source to generate electricity, only the RECs associated with the proportion of the total electric output of the renewable energy system that results from the use of renewable energy resources shall be eligible to count toward compliance with the RES.

(i) If an on-site solar systems of ten kW or below has received a one-time REC payment from a QRU under rule 3658, the QRU shall be entitled to count the anticipated RECs purchased by the one-time REC payment for compliance with the RES even if the on-site solar systems is removed or becomes inoperable.

(j) All renewable energy resources located in the region covered by the Western Electricity Coordinating Council (WECC) that generate RECs used by an investor owned QRU for compliance with the RES shall be registered with the Western Renewable Energy Generation Information System (WREGIS) and shall record their RECs in WREGIS with the exception of retail renewable distributed generation facilities less than one MW.

(k) All investor owned QRUs shall register in WREGIS. The investor owned QRU shall recover through its RESA the costs associated with WREGIS that are allocated to its retail customers.

(l) To the extent that the investor owned QRU acquires RECs from renewable energy resources that are not recorded in WREGIS, the investor owned QRU shall record such RECs in a central database. The database shall include, but not be limited to, a list of the renewable distributed generation whose RECs the investor owned QRU intends to use for compliance with the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655, including its type, location, owner, operator, and start of operation. The database shall also record the RECs generated and the ownership, transfer and retirement of those RECs.

(m) An investor owned QRU may own and use for compliance with the RES RECs generated by renewable energy resources that the Commission has designated as new energy technologies or demonstration projects under § 40-2-123(1)(a), C.R.S., and that are therefore not subject to the retail rate impact established in rule 3661.

(n) The investor owned QRU shall have the discretion to sell or trade RECs at any time as long as the investor owned QRU obtains and retires sufficient levels of RECs to comply with the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655. Proceeds from the sales of RECs shall be credited to the account associated with the RESA. The investor owned QRU may seek approval in an annual compliance plan filing under rule 3657 or by separate application to retain as earnings a percentage of the funds from REC sales that the investor owned QRU expects to have available to acquire eligible energy and RECs under the retail rate impact in rule 3661 for the compliance year. In considering the percentage of funds to be retained as earnings by the investor owned QRU, the Commission shall take into account the development of the REC market and the expected value added by the investor owned QRU in marketing and trading the RECs.

3660. Cost Recovery and Incentives.

(a) The investor owned QRU shall be entitled to timely cost recovery through retail rate mechanisms for all funds prudently expended to comply with these rules, including the costs the QRU incurs to administer the standard rebate offer and the acquisitions of eligible energy and RECs. The QRU shall be entitled to recover its investment and expenses associated with these rules through appropriate adjustment clauses, including the RESA, that allow recovery of expenditures without the full resetting of electric rates.

(b) In its compliance plans and reports, the investor owned QRU must demonstrate that the RESA satisfies the retail rate impact established in paragraph 3661(a).

(c) So long as the RESA does not exceed the retail rate impact under paragraph 3661(a) and in accordance with either an approved resource plan under the Commission's Electric Resource Planning Rules or an approved compliance plan under rule 3657, the investor owned QRU may:

(I) collect and bank funds in the RESA account for acquiring eligible energy in future periods; and

(II) advance funds from compliance year to compliance year to augment the amounts collected from the RESA for the acquisition of more eligible energy resources.

(d) Each QRU shall separately identify the RESA on its customers' bills.

(e) Interest shall accrue on the deferred balance (positive or negative) of the RESA account at the investor owned QRU's most recent authorized after-tax weighted average cost of capital, so long as the RESA does not exceed two percent of the total annual electric bill for each customer.

(f) If the investor owned QRU incurs costs in acquiring eligible energy to meet the RES, the QRU shall be entitled to carry forward these costs to a future year for cost recovery so long as the investor owned QRU complies with limit on the retail rate impact under paragraph 3661(a).

(g) The investor owned QRU shall be entitled to earn an extra profit on the QRU's ownership investment in a specific eligible energy resource if that eligible energy resource provides net economic benefits to customers. For these investments, the QRU shall be entitled to a return equal to the QRU's most recent authorized rate of return on rate base plus a bonus limited to 50 percent of the of the net economic benefit as long as the QRU is in compliance with these rules implementing the RES. If the QRU's investment in a specific eligible renewable energy resource does not provide a net economic benefit to customers, the QRU shall be entitled to a return equal to the QRU's most recent authorized rate of return on rate base.

(I) For the purposes of this rule 3660, net economic benefit shall mean that the specific eligible energy resource in which the QRU has made an ownership investment results in an average retail rate impact less than the rate impact that would have resulted from the acquisition of the alternative eligible energy resource meeting the same component of the RES that would have been selected absent the QRU's investment. The QRU shall set forth its calculation of the proposed net economic benefit either at the time of a compliance plan filing, an annual compliance report filing, a QRU rate filing or by application. The Commission shall determine the level of the net economic benefit and the level of the bonus after review of the utility's filing. The Commission may set the matter for hearing if appropriate under the Commission's Rules of Practice and Procedure.

(II) To the extent that a QRU uses computer modeling in its analysis of net economic benefit, the QRU shall use the same methodologies and assumptions it used in its most recently approved electric resource planning case, except as otherwise approved by the Commission. Confidential information may be protected in accordance with rules 1100 through 1103 of the Commission's Rules of Practice and Procedure.

(III) Any net economic benefit for which the QRU qualifies to receive a bonus shall be charged against the RESA account.

(h) An investor owned QRU may propose to develop and own, in whole or in part, a new eligible energy resource by filing an application with the Commission. The Commission may set the matter for hearing, if appropriate, under the Commission's Rules of Practice and Procedure. For the purpose of this paragraph 3660(h):

(I) A QRU shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in rule3656, up to twenty-five percent of the total new eligible energy resources that the QRU acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007 if the Commission determines that the QRU-owned new eligible energy resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market.

(II) A QRU shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in rule 3656, up to fifty percent of the total new eligible energy resources that the QRU acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007 if the Commission determines that the QRU-owned new eligible energy resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market and that the proposed new eligible energy resource would provide significant economic development, employment, energy security, or other benefits to the state of Colorado.

(III) The QRU shall be allowed to develop and own as utility rate-based property more than the percentages of total new eligible energy resources set forth in rules 3660(h)(I) and (h)(II), if the QRU bids to own the new eligible energy resources in a competitive solicitation and is selected as a winning bidder in that competitive solicitation.

(IV) The QRU may develop and own new eligible energy resources either solely or jointly with other owners. If the QRU owns the new eligible energy resource jointly, the entire jointly owned resource shall count toward the percentage limitations set forth in paragraph 3660(h). For purposes of this rule, participation by any parent, affiliate or subsidiary of a QRU in a QRU's owned new eligible energy resource shall count towards the percentage limitations. The QRU's rate base portion of any new eligible energy resource is limited to only the QRU's ownership percentage in the new eligible energy resource.

(V) If the QRU intends to develop and own new eligible energy resources as provided for under subparagraphs 3660(h)(I) or (h)(II), it shall propose for Commission approval, in advance of filing its application under this rule, the name of the independent evaluator whom the utility intends to hire to conduct an assessment of whether the proposed new eligible energy resources can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market. The independent evaluator will develop a report to the Commission on its assessment of whether the proposed new eligible energy resources can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market. The independent evaluator shall have at least five years’ experience conducting and/or reviewing the conduct of competitive electric utility resource acquisition, including computerized portfolio costing analysis. The independent evaluator shall be unaffiliated with the utility; and shall not, directly or indirectly, have benefited from employment or contracts with the utility in the preceding five years, except as an independent evaluator under these rules. The independent evaluator shall not participate in, or advise the utility with respect to, any decisions relating to the proposed new eligible energy resource. The utility shall conduct any additional modeling requested by the independent evaluator to test the assumptions and results of the cost analyses. The independent evaluator’s report shall be filed with the utility’s application for approval of the proposed new eligible energy resource. The evaluator’s report shall contain the evaluator’s views on whether the proposed new eligible energy project can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market.

(VI) Nothing in paragraph 3660(h) shall prevent the Commission from waiving, repealing, or revising any Commission rule in a manner otherwise consistent with applicable law.

(i) When an investor owned QRU applies for a certificate of public convenience and necessity, the Commission shall consider rate recovery mechanisms that provide for earlier and timely recovery of costs prudently and reasonably incurred by the QRU in developing, constructing, and operating the eligible energy resource, including: rate adjustment clauses until the costs of the eligible energy resource can be included in the utility's base rates; and, a current return on the utility's capital expenditures during construction at the utility's most recently authorized weighted average cost of capital, including its cost of debt and its most recently authorized rate of return on equity, during the construction, startup, and operation phases of the eligible energy resource.

(j) The utility is entitled to recover through rates, its prudently incurred expenditures. While not the exclusive method for establishing prudence, if the Commission approves a renewable energy supply contract or a renewable energy credit contract, the expenditures of the investor owned QRU under the contract shall be deemed to be prudent expenditures.

(k) If the investor owned QRU recovers fuel and purchased energy expense through an incentive adjustment clause, the QRU shall not receive a benefit from the incentive adjustment clause for the energy generated from QRU-owned eligible renewable energy resources, but the QRU shall be entitled to recover all the fuel and purchased energy costs associated with the eligible energy resource.

(l) Each wholesale energy provider shall offer to its wholesale customers that are cooperative electric associations the opportunity to purchase their load ratio share of the wholesale energy provider's electricity from eligible energy resources. If a wholesale customer agrees to pay the full costs associated with the acquisition of eligible energy resources and associated renewable energy credits by its wholesale provider by providing notice of its intent to pay the full costs within sixty days after the wholesale provider extends the offer, the wholesale customer shall be entitled to receive the appropriate credit toward the RES as well as any associated renewable energy credits. To the extent that the full costs are not recovered from wholesale customers, a qualifying retail utility shall be entitled to recover those costs from retail customers.

3661. Retail Rate Impact.

(a) The net retail rate impact of actions taken by an investor owned QRU to comply with the RES shall not exceed two percent of the total electric bill annually for each customer of that QRU. However, a retail customer who installs renewable distributed generation may pay a RESA charge under paragraph 3664(h) that exceeds two percent of that customer's annual electric bill.

(b) The net retail rate impact of actions taken by a cooperative electric association QRU to comply with the RES shall not exceed two percent of the total electric bill annually for each customer of that QRU.

(c) The net retail rate impact shall include the prudently incurred direct and indirect costs of all actions by a QRU to meet the RES, including, but not limited to, program administration, rebates and performance-based incentives, payments under renewable energy supply contracts, payments under renewable energy credit contracts, payments made for RECs purchased through brokers or exchanges, computer modeling and analysis time, QRU investment in and return on investment for eligible energy resources, and expenditures made to purchase unsubscribed energy and RECs from CSGs.

(d) The administrative costs of a QRU to implement these rules are capped at ten percent per year of the total annual collection. A QRU may include in its compliance plan a waiver request of this rule during the initial ramp-up stage of the QRU's program.

(e) For purposes of calculating the retail rate impact, the investor owned QRU shall use the same methods and assumptions it used in its most recently approved electric resource plan under the Commission's Electric Resource Planning Rules, unless otherwise approved by the Commission. Confidential information may be protected in accordance with rules 1100 through 1102 of the Commission's Rules of Practice and Procedure.

(f) In its compliance plan filed under rule 3657, the investor owned QRU shall estimate the retail rate impact of its plan to comply with the RES at the time of the beginning of the compliance period year and for a minimum of the ten years thereafter (the "RES planning period") and shall submit a report detailing the development of the retail rate impact estimate. The compliance plan shall identify the funds that need to be made available to the QRU, including RESA account balances over the RES planning period and any carried-forward deferred account balances from before the RES planning period, to comply with the RES under rule 3654, the requirements for renewable distributed generation under rule 3655, and the retail rate impact under this rule 3661.

(g) The retail rate impact shall be determined net of new alternative sources of electricity supply from non-eligible energy resources that are reasonably available at the time of the determination.

(h) The basic method for investor owned QRUs for performing the estimate of the retail rate impact cap is as follows.

(I) The QRU shall determine all commercially available resources to the QRU, either through ownership or by contract, for the RES planning period. The projected costs of these available resources shall be reflected in both of the scenarios analyzed under this paragraph.

(II) The QRU shall determine the QRU's capacity and energy requirements over the RES planning period. The QRU shall develop two scenarios to estimate the resource composition of the QRU's future electric system and the cost and benefits of that system over the RES planning period. The first scenario, a RES plan or "RES plan" should reflect the QRU's plans and actions to acquire new eligible energy resources necessary to meet the RES. The second scenario, a "No RES plan" should reflect the QRU's resource plan that replaces the new eligible energy resources in the RES plan with new nonrenewable resources reasonably available.

(III) Eligible energy resources whose acquisition commenced prior to July 2, 2006 shall be included in both the RES and No RES plans. Eligible energy resources acquired pursuant to a Commission-approved electric resource plan as new energy technologies or demonstration projects under § 40-2-123(1)(a), C.R.S., shall be included in both the RES and No RES plans.

(IV) The QRU shall compare the costs and benefits of the two plans to project the estimated annual net retail rate impact for the RES planning period. The maximum retail rate impact shall not exceed two percent of the total retail bill annually for each customer. To the extent the RES plan exceeds this maximum retail rate impact over the RES planning period, the investor owned QRU shall modify the RES plan to limit the acquisition of eligible energy resources so as not to exceed the maximum retail rate impact for the RES planning period. In calculating the net retail rate impact, the QRU shall take into account the projected net retail rate impact of the new eligible energy resources and the sum of the on-going annual net incremental costs of all eligible energy resources that the investor owned QRU has contracted to acquire under the SRO programs under rule 3658 and all eligible energy from resources that were constructed by the investor owned QRU or contracted for by the investor owned QRU after July 2, 2006.

(V) The on-going annual net incremental costs used in the retail rate impact calculation under subparagraph 3661(h)(IV) shall be established in each compliance plan filed under rule 3657. These costs shall then be locked down until the Commission issues a final decision regarding the investor owned QRU's next compliance plan filing when such costs shall be unlocked and reset to reflect changes in methods and assumptions used by the investor owned QRU under the Commission's Electric Resource Planning Rules, unless otherwise approved by the Commission. On-going annual net incremental costs locked down before October 31, 2015 shall not be reset until the Commission issues a final decision regarding the investor owned QRU's compliance plan filed on or before October 31, 2015.

(VI) If, in a compliance plan filed under rule 3657, the Commission approves a calculation of the retail rate impact that differs from a calculation in an earlier approved plan, the Commission shall allow the investor owned QRU to fully recover the costs of eligible energy resources and RECs already acquired by the investor owned QRU through one or more adjustment clauses.

(i) If the retail rate impact does not exceed the maximum percent level, a QRU may acquire more than the minimum amount of eligible energy resources and RECs required under the RES.

3662. Annual RES Compliance Report.

(a) Each investor owned and cooperative electric association QRU shall file an annual RES compliance report no later than June 1 to report on the status of the QRU's compliance with the RES for the most recently completed compliance year. Unless expressly noted otherwise, the annual RES compliance report of each investor owned and cooperative electric association QRU shall provide the following information for the most recently completed compliance year

(I) The total MWH sold by the QRU to its retail customers in Colorado and the associated eligible energy required for compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable.

(II) The total amount and source of eligible energy and RECs acquired by the QRU during the compliance year for to meet the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable. The QRU shall separately identify and quantify amounts of eligible energy and RECs by each type of resource, including residential retail renewable distributed generation and nonresidential renewable distributed generation, as applicable. The QRU shall also separately identify eligible energy and RECs generated by early eligible energy resources.

(III) The total amount of RECs by category acquired by the investor owned QRU during the compliance year and the total amount and source of eligible energy generated by the QRU-owned eligible energy resources.

(IV) The total amount of eligible energy and RECs borrowed forward, pursuant to rule 3654, in previous compliance years that were made up during the compliance year to achieve compliance with each component of the RES.

(V) The total amount of eligible energy and RECs borrowed forward, pursuant to rule 3654, from future compliance years to achieve compliance with each component of the RES in the compliance year.

(VI) The total amount and source of eligible energy and RECs the QRU is carrying back from the year following the compliance year under rule 3654 to achieve compliance with each component of the RES in the compliance year.

(VII) The total amount of eligible energy and RECs the QRU has carried forward from prior calendar years under rule 3654 to apply in the compliance year for each component of the RES.

(VIII) The total amount of eligible energy and RECs the QRU has acquired in the compliance year that the QRU proposes to carry forward under rule 3654 to future years for each component of the RES.

(IX) The total amount of eligible energy and RECs the QRU has counted toward compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable, in the compliance year. The QRU shall separately identify amounts of renewable energy by each type of resource and eligible energy or RECs generated by early eligible energy resources.

(X) The total amount of renewable energy or RECs acquired by the QRU during the compliance year pursuant to the SRO program.

(XI) The total amount of RECs retired by the investor owned QRU during the compliance year pursuant to a voluntary green pricing program.

(XII) The total amount of RECs sold or traded by the investor owned QRU during the compliance year along with the profit and losses of such transactions and the method for calculating these margins.

(XIII) Whether the QRU has invested in any eligible energy resource and whether that resource is under construction or in operation.

(XIV) The funds expended from the RESA account and other revenue sources and the retail rate impact of the eligible energy and RECs acquired by the investor owned QRU. If the investor owned QRU has not acquired sufficient eligible energy and RECs to meet the RES under rule 3654 or the requirements for renewable distributed generation under rule 3655 due to the retail rate impact cap under rule 3661, the retail rate impact cap shall be recalculated based on the actual compliance year values. To the extent the recalculation of the retail rate impact cap demonstrates that additional funds are available based on actual compliance year values, the investor owned QRU shall use those additional funds to acquire RECs, to the extent necessary, to achieve the compliance levels set forth in rules 3654 and 3655 or until the additional funds have been spent if the investor owned QRU intends to claim that the retail rate impact cap prevented it from achieving compliance with the standard.

(XV) A description of the method used to develop the retail rate impact calculation.

(XVI) The proposed calculation of on-going annual net incremental costs for eligible energy resources that will come on line prior to the end of the following compliance year that have not been locked down pursuant to an investor owned QRU's compliance plan filing.

(XVII) The funds advanced by the investor owned QRU during the compliance year, if any, to augment the amounts collected from retail customers through the RESA.

(XVIII) The average hourly incremental cost of electricity during the compliance year, the total number of CSG kWh which were unsubscribed for each CSG during that period, and the total kWh and corresponding billing credits paid to CSG subscribers during the compliance year by each retail rate class for each CSG.

(b) In the annual RES compliance report filed by the investor owned or cooperative electric association QRU, the QRU must explain whether it achieved compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable, during the most recently completed compliance year, or explain why the QRU had difficulty meeting the RES or the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable.

(c) If, in its annual RES compliance report, the investor owned QRU did not comply with its RES as a direct result of absolute limitations within a requirements contract from a wholesale electric supplier, then the QRU must explain whether it acquired a sufficient amount of either eligible RECs or documented and verified energy savings through energy efficiency and/or conservation programs, or both to rectify the noncompliance so as to excuse the investor owned QRU from any administrative fine or other administrative action.

(d) On the same date that the investor owned or cooperative electric association QRU files its annual RES compliance report, the QRU shall post its annual compliance report excluding confidential material on its website to facilitate public access and review.

(e) On the same date that the investor owned or cooperative electric association QRU files its annual RES compliance report, if the QRU did not file using the Commission's E-Filings System, it shall provide the Commission with an electronic version of its annual compliance report excluding confidential material. The Commission may place the non-confidential portion of each QRU's annual compliance report on the Commission's website in order to facilitate public review.

(f) Each qualifying wholesale utility shall submit an annual report to the Commission no later than June 1 of each year. In addition, the qualifying wholesale utility shall post each annual report on its website. In each annual report, the qualifying wholesale utility shall:

(I) describe the steps it took during the most recently completed compliance year to comply with the RES of 20 percent of retail sales by 2020 as established in § 40-2-124(8), C.R.S.;

(II) for the compliance years before 2020, describe whether it is making sufficient progress toward meeting the standard in 2020 or is likely to meet the 2020 standard early. If it is not making sufficient progress toward meeting the standard of 20 percent in 2020, it shall explain why and shall indicate the steps it intends to take to increase the pace of progress; and

(III) for the 2020 compliance year and each compliance year thereafter, describe whether it has achieved compliance with the RES established in § 40-2-124(8), C.R.S., and whether it anticipates continuing to do so. If it has not achieved such compliance or does not anticipate continuing to do so, it shall explain why and shall indicate the steps it intends to take to meet the standard and by what date.

3663. RES Compliance Report Review.

(a) RES compliance reporting for investor owned QRUs.

(I) In the annual RES compliance report, the QRU must explain whether it complied with its RES and whether it satisfied the requirements for renewable distributed generation during the most recently completed compliance year.

(II) Upon receipt of the QRU annual RES compliance report, the Commission will provide notice to interested persons. Interested persons will have 30 days within which to provide comment to the Commission on the content of the annual compliance report. The QRU shall have the opportunity to reply to all comments on or before 45 days following the filing of the annual compliance report.

(III) Commission staff shall review the annual RES compliance report and any comments received and within 60 days of the filing of the annual compliance report make a recommendation to the Commission as to whether:

(A) no action should be taken by the Commission because the QRU has met the RES and the requirements for renewable distributed generation and has correctly calculated the on-going annual net incremental costs for new eligible energy resources under subparagraph 3662(a)(XVI);

(B) changes are needed to the RES compliance report; or

(C) a hearing is necessary.

(IV) Upon review of the QRU's annual RES compliance report, Commission staff recommendation and all comments filed, the Commission will issue an order stating whether:

(A) the QRU complied with the RES during the most recently completed compliance year;

(B) the QRU satisfied the requirements for renewable distributed generation during the most recently completed compliance year;

(C) the QRU has correctly calculated the on-going annual net incremental costs for new eligible energy resources under subparagraph 3662(a)(XVI); and

(D) a hearing is necessary.

(V) If the Commission determines that the total number of RECs which the QRU generated or acquired from renewable energy systems during the most recently completed compliance year exceeded the total number of RECs which the QRU needed to comply with its RES or with its requirements for renewable distributed generation for the recently completed compliance year:

(A) the Commission will state in its order the number of excess RECs which the QRU has available to carry forward from that compliance year or use for any other legal purpose; and

(B) the QRU may use those excess RECs to comply with its RES or with its requirements for renewable distributed generation for the five compliance years immediately following that compliance year.

(b) RES compliance report hearing for investor owned QRUs.

(I) If the Commission determines that the QRU did not comply with its RES or with its requirements for renewable distributed generation during the most recently completed compliance year, the Commission will determine whether the QRU failed to meet the RES because of the retail rate impact limit. The Commission will state in its order:

(A) the number of RECs by which the QRU failed to comply with its RES or with its requirements for renewable distributed generation; and

(B) whether the Commission is satisfied that the failure to meet the RES or the requirements for renewable distributed generation was due to the retail rate impact limit. If the Commission is not satisfied on this issue, the Commission will issue a notice of possible noncompliance and schedule an evidentiary hearing on the matter.

(II) At the evidentiary hearing, if the QRU asserts that the RES or the requirements for renewable distributed generation was not met due to the retail rate impact, it will have the burden of proof that it failed to comply with its RES or its requirements for renewable distributed generation during the most recently completed compliance year because of the retail rate impact.

(III) At the evidentiary hearing, any party that advocates that the QRU failed to comply with the QRU's RES or its requirements for renewable distributed generation during the most recently completed compliance year is the proponent of a Commission order finding non-compliance, and that party shall have the burden of proof that the QRU failed to comply with the RES or the requirements for renewable distributed generation during the most recently completed compliance year. The QRU may assert that the RES or the requirements for renewable distributed generation was not met due to events beyond the reasonable control of the QRU that could not have been reasonably mitigated.

(IV) If the Commission determines that the QRU did not correctly calculate the on-going annual net incremental costs for new eligible energy resources under subparagraph 3662(a)(XVI), the Commission will determine the correct on-going annual net incremental costs to be applied in the retail rate impact calculation.

(c) Compliance penalties for investor owned QRUs.

(I) After notice and hearing, if the Commission determines that the QRU did not fully comply with its RES or with its requirements for renewable distributed generation during the most recently completed compliance year, the Commission shall determine what, if any, administrative penalties should be assessed against the QRU for its failure to meet the RES or the requirements for renewable distributed generation. In assessing penalties, the Commission may take one or more of the following actions.

(A) Determine the cost that would have been incurred by the QRU to fully comply with the RES or the requirements for renewable distributed generation through the acquisition of RECs and assess all or part of this amount as part of an administrative penalty.

(B) No administrative penalties shall be assessed against a QRU if the amount of the shortfall is attributable to the retail rate impact limit.

(C) Assess no administrative penalties against a QRU if the failure to meet the RES or the requirements for renewable distributed generation results from events beyond the reasonable control of the QRU that could not have been reasonably mitigated including, but not limited to, failures to perform by counterparties to renewable energy supply contracts and renewable energy credit contracts, events that delay the construction or commercial operation of QRU-owned eligible renewable energy resources, and lack of customer interest in the SRO.

(II) The cost of such administrative penalties shall not be recovered from retail customers through the QRU's rates.

3664. Net Metering.

(a) Except as provided in paragraph 3664(i), all investor owned QRUs shall allow the customer's retail electricity consumption to be offset by the electricity generated from retail renewable distributed generation, provided that the generating capacity of the customer's facility meets the following two criteria:

(I) the retail renewable distributed generation shall be sized to supply no more than 120 percent of the customer's average annual electricity consumption at that site, where the site includes all contiguous property owned or leased by the consumer, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way; and

(II) the rated capacity of the retail renewable distributed generation does not exceed the customer's service entrance capacity.

(b) If a customer with retail renewable distributed generation generates renewable energy pursuant to paragraph 3664(a) in excess of the customer’s consumption, the excess kWh shall be carried forward from month to month and credited at a ratio of 1:1 against the customer’s retail kWh consumption in subsequent months. Within 60 days of the end of each calendar year, or within 60 days of when the customer terminates its retail service, the investor owned QRU shall compensate the customer for any accrued excess kWh credits, at the investor owned QRU's average hourly incremental cost of electricity supply over the most recent calendar year. However, the customer may make a one-time election, in writing, on or before the end of a calendar year, to request that the excess kWh be rolled over as a credit from month to month indefinitely until the customer terminates service with the investor owned QRU, at which time no payment shall be required from the investor owned QRU for any remaining excess kWh credits supplied by the customer.

(c) A customer’s retail renewable distributed generation shall be equipped with metering equipment that can measure the flow of electric energy in both directions. The investor owned QRU shall utilize a single bi-directional electric meter.

(d) If the customer’s existing electric meter does not meet the requirements of these rules, the investor owned QRU shall install and maintain a new meter for the customer, at the company's expense. Any subsequent meter change necessitated by the customer shall be paid for by the customer.

(e) The investor owned QRU shall not require more than one meter per customer to comply with this rule 3664. Nothing in this rule 3664 shall preclude the QRU from placing a second meter to measure the output of a solar renewable energy system for the counting of RECs subject to the following conditions.

(I) For customer facilities over ten kW, a production meter shall be required to measure the solar renewable energy system output for the counting of RECs.

(II) For systems ten kW and smaller, a production meter may be installed under either of the following circumstances:

(A) the QRU may install a production meter on the solar renewable energy system output at its own expense if the customer consents; or

(B) the customer may request that the QRU install a production meter on the solar renewable energy system output in addition to the meter at the customer's expense.

(III) If the on-site solar system is not owned by the electric consumer, the owner or operator of the on-site solar system shall pay the cost of installing the production meter.

(f) An investor owned QRU shall provide net metering service at non-discriminatory rates to customers with retail renewable distributed generation. A customer shall not be required to change the rate under which the customer received retail service in order for the customer to install retail renewable distributed generation. Nothing in this rule shall prohibit an investor owned QRU from requesting changes in rates at any time.

(g) Unless the Commission approves under § 40-2-124(1)(g)(IV)(B), C.R.S., an alternative surcharge for net metered customers served by an investor owned QRU, the investor owned QRU shall bill a retail customer receiving net metering service a surcharge to supplement that customer's contribution toward the investor owned QRU's RESA account.

(I) For retail renewable distributed generation that is production metered, the surcharge shall increase the customer's total contribution to the investor owned QRU's RESA account to the calculated level it would have been had all of the customer's consumption been billed at the investor owned QRU's applicable rates.

(II) For retail renewable distributed generation that is not production metered, the surcharge shall increase the customer's total contribution to the investor owned QRU's RESA account as follows, based upon the size of the customer's system.

(A) For customers with a system that is from 500 watts to five kW, a 500 kWh volume proxy shall be used. The 500 kWh volume proxy will be multiplied by the current monthly per kWh effective residential energy rate and effective riders. That product will then be multiplied by two percent to obtain the customer's RESA contribution amount.

(B) For customers with a system that is from five kW up to ten kW, a 1,000 kWh volume proxy shall be used. The 1,000 kWh volume proxy will be multiplied by the current monthly per kWh effective residential energy rate and effective riders. That product will then be multiplied by two percent to obtain the customer's RESA contribution amount.

(h) If more than one meter is used to measure the electricity consumption of a customer with retail renewable distributed generation at the premises where the retail renewable distributed generation is installed, the following provisions apply:

(I) An investor owned QRU must, upon request from such customer, aggregate for billing purposes a meter to which the retail renewable distributed generation is physically attached (the designated meter) with one or more meters (the additional meters) in the manner set out in this paragraph when:

(A) each additional meter is located on the customer's contiguous property; and

(B) each additional meter is used to measure only the customer's own electricity consumption.

(II) A net metering customer must give at least 30 days' notice to the QRU to request that additional meters be aggregated pursuant to this paragraph. The specific designated and additional meters must be identified at the time of such request. In the event that more than one additional meter is identified, the utility shall apply the net metering kWh credits to the sum of the kWh consumption as measured by the designated and additional meters.

(III) If, in a monthly billing period, the customer's retail renewable distributed generation generates more renewable energy than the customers' consumption as measured by the designated and additional meters, the excess kWh credits will be rolled over as a credit from month to month indefinitely until the customer terminates service with the investor owned QRU, at which time no payment shall be required from the investor owned QRU for any remaining excess kWh credits supplied by the customer.

(IV) All meters aggregated pursuant to this paragraph must be on the same rate schedule.

(i) Pursuant to § 24-33-115(2), C.R.S., for the Colorado Division of Parks and Outdoor Recreation (CDPOR) as the customer of an investor owned QRU, the investor owned QRU may, on a case-by-case or project-by-project basis:

(I) waive any existing limits on the net metering of electricity generated on contiguous property constituting the CDPOR customer's site;

(II) waive any existing limits on generating capacity or customer service entrance capacity if the customer proposes to make any necessary upgrades to its service entrance capacity at its own expense; and

(III) have the right of first refusal to purchase, and the right not to purchase, electricity from retail renewable distributed generation that is sized to provide more than 120 percent of the average annual consumption of electricity by the CDPOR customer at that site. If the investor owned QRU exercises its option to purchase excess generation under this subparagraph 3664(i)(III), it may claim the RECs based on such purchases.

(IV) This paragraph does not confer upon CDPOR the right to make retail sales of electricity or distribute electricity to other state agencies or to noncontiguous properties.

3665. Community Solar Gardens.

The following rules shall apply to all community solar gardens (CSGs) developed pursuant to § 40-2-127, C.R.S. These rules shall not apply to cooperative electric associations or to municipally owned utilities.

(a) CSG subscriptions, subscribers, and subscriber organizations.

(I) Requirements for CSG subscribers, CSG subscriptions, and CSG subscriber organizations.

(A) No CSG subscriber may own more than a 40 percent interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG.

(B) Each CSG subscription shall be sized to represent at least one kW of the CSG's nameplate rating and supply no more than 120 percent of the CSG subscriber's average annual electricity consumption at the premise to which the subscription is attributed, with a deduction for the amount of any existing retail renewable distributed generation at such premise. The minimum one kW sizing requirement herein shall not apply to subscriptions owned by an eligible low-income CSG subscriber.

(C) The premise to which a subscription is attributed by a CSG subscriber shall be served by the investor owned QRU and shall be within the same county as, or a county adjacent to, the CSG. The CSG subscriber may change from time to time the premise to which the CSG subscription shall be attributed, so long as the premise is served by the investor owned QRU and is within the same county as, or a county adjacent to, the CSG.

(D) No CSG subscriber organization may own more than a 40 percent interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG, after the CSG has operated commercially for 18 months.

(II) Share transfers and portability.

(A) A CSG subscription may be transferred or assigned to the associated CSG subscriber organization or to any person or entity who qualifies to be a subscriber in the CSG.

(B) A CSG subscriber who desires to transfer or assign all or part of his subscription to the CSG subscriber organization, in its own name or to become unsubscribed shall notify the CSG subscriber organization and the transfer of the subscription to the CSG subscriber organization shall be effective upon such notification, unless the CSG subscriber specifies a later effective date.

(C) A CSG subscriber who desires to transfer or assign all or part of his subscription to an eligible QRU customer desiring to purchase a subscription may do so only in compliance with the terms and conditions of the subscription and will be effective in accordance therewith.

(D) If the CSG is fully subscribed, the CSG subscriber organization shall maintain a waiting list of eligible QRU customers who desire to purchase subscriptions. The CSG subscriber organization shall offer the CSG subscription of the CSG subscriber desiring to transfer or assign their interest, or a portion thereof, on a first-come, first-serve basis to customers on the waiting list.

(E) The CSG subscriber organization and the investor owned QRU shall jointly verify that each CSG subscriber is eligible to be a subscriber in the CSG pursuant to subparagraph 3665(a)(I). The CSG subscriber roll shall include, at a minimum, the percentage share owned by the CSG subscriber, the effective date of the ownership of that percentage share, and the meters at the premises to which the CSG subscription is attributed for the purpose of applying billing credits. Changes in the CSG subscriber roll shall be communicated by the CSG subscriber organization to the QRU, in written or electronic form, as soon as practicable, but on no less than a monthly basis.

(F) Prices paid for subscriptions in a CSG shall not be subject to regulation by the Commission.

(b) Production data.

(I) The amount of renewable energy and RECs generated by each CSG shall be measured by a production meter installed by the investor owned QRU or the CSG owner and paid for by the CSG owner.

(II) The owner of a CSG with a nameplate rating of one MW or greater shall register the CSG and report the CSG’s production data to the WREGIS in accordance with paragraph 3659(j).

(III) CSGs are required to provide real time reporting of production as specified by the QRU. For CSGs greater than 250 kW, the CSG owner shall provide real time electronic access to production data under paragraph 3656(l). A QRU may require different real time reporting for CSGs 250 kW and smaller.

(IV) Production from the CSG shall be reported by the CSG subscriber organization to its CSG subscribers at least monthly. To facilitate the tracking of production data by CSG subscribers, CSG owners or CSG subscriber organizations are encouraged to provide website access to subscribers showing real time output from the CSG, if practicable, as well as historical production data.

(c) Billing credits and unsubscribed renewable energy.

(I) Compensation to the CSG subscriber for its share of the renewable energy generated by a CSG shall take the form of a billing credit paid to the CSG subscriber by the investor owned QRU.

(A) The billing credit shall be calculated by multiplying the CSG subscriber's share as a percentage of the renewable energy generated by the CSG times the QRU's total aggregate retail rate (including all billed components) as charged to the CSG subscriber.

(B) For the purpose of calculating the billing credit for a commercial or industrial customer on a demand tariff, the total aggregate retail rate (including all billed components) shall be determined by dividing the total electric charges to be paid by the customer to the investor owned QRU for the most recent calendar year (including demand charges) by the customers' total electricity consumption for that year. In the event that the designated premises to which the CSG subscription is attributed has less than one year of billing history, an estimate of the total annual charges shall be made by the QRU.

(C) Billing credits shall be reflected in the CSG subscriber's bill from the investor owned QRU no later than the 60th day after the QRU receives the information required to calculate the billing credit from the CSG subscriber organization.

(II) The investor owned QRU may assess a Commission-approved charge to cover the QRU's costs of delivering to the CSG subscriber's premises the renewable energy generated by the CSG, integrating the generation from the CSG into the utility's system, and administering the contracts with CSG owners and billing credits. This charge shall be a fixed amount and shall not reflect costs that are already recovered by the QRU from CSG subscribers through other charges. The QRU may seek a revision of this charge no more frequently than once per year in conjunction with its acquisition plan submitted under paragraph 3665(d).

(III) If, in a monthly billing period, the CSG subscriber's billing credit associated with a CSG subscription exceeds the customer's bill from the investor owned QRU, the excess billing credit will be rolled over as a credit from month to month indefinitely until the customer terminates service with the investor owned QRU, at which time no payment shall be required from the investor owned QRU for any remaining billing credits associated with the customer's CSG subscription..

(IV) The investor owned QRU shall purchase all of the renewable energy and RECs generated by a CSG if the QRU enters into a contract with the CSG owner pursuant to a Commission-approved acquisition plan under paragraph 3665(d). For RECs purchased by the QRU, the QRU and the CSG owner shall agree on whether subscribers will be compensated by a credit on each CSG subscriber's bill from the QRU or by a payment to the CSG owner.

(V) The investor owned QRU shall purchase from the CSG owner the unsubscribed renewable energy and RECs at a rate equal to the QRU's average hourly incremental cost of electricity supply over the immediately preceding calendar year.

(d) Acquisitions of renewable energy and RECs from CSGs.

(I) The Commission shall establish the minimum and maximum purchases of renewable energy from newly installed CSG generation (new CSGs) by the investor owned QRU for each compliance year under the RES. For compliance years 2014 and thereafter, the Commission shall determine the minimum and maximum purchases of renewable energy and RECs from new CSGs of different segments based on the capacity of the CSGs (capacity segments) without regard to the six MW ceiling for the period 2011 through 2013. The Commission shall establish such minimum and maximum levels of purchases in consideration of a plan for the acquisition of renewable energy and RECs from CSGs filed by the investor owned QRU. The investor owned QRU's plan for the acquisition of renewable energy and RECs from CSGs shall be part of the investor owned QRU's RES compliance plan filed pursuant to rule 3657.

(II) The investor owned QRU shall acquire renewable energy and RECs by entering into contracts with CSG owners. A CSG whose owner enters into a contract with the QRU shall be deemed to be part of the QRU's Commission-approved acquisition plan if the cumulative total of the nameplate capacity of the new CSGs acquired in the compliance year does not exceed the maximum purchases established by the Commission for that compliance year.

(III) The investor owned QRU shall conduct due diligence on proposed contracts with new CSG owners to reasonably assure that the CSG owner and CSG subscriber organization have sufficient resources to successfully construct and commence operations of the CSG.

(A) Except for CSGs owned by governmental or quasi-governmental entities, the investor owned QRU shall be deemed to have conducted sufficient due diligence by requiring from the CSG owner documentation of escrowed funds of not less than $100 per kW of the CSG's nameplate rating. The escrow shall be maintained by its terms until such time as the CSG commences commercial operation as certified by the QRU's acceptance of renewable energy generated by the CSG.

(B) If a CSG owner properly documents escrowed funds consistent with this subparagraph 3665(d)(IV), the investor owned QRU may not refuse to enter into a contract with the CSG owner for failure to demonstrate sufficient resources to reasonably assure successful construction and commencement of CSG operations.

(IV) In each plan to acquire renewable energy and RECs from CSGs, the investor owned QRU shall reserve, to the extent there is demand for such ownership, at least five percent of its renewable energy purchases from new CSGs for eligible low-income CSG subscribers.

(A) CSG subscriber organizations and investor owned QRUs may rely on certification by the Colorado Department of Human Services for acceptance in the Colorado Low-Income Energy Assistance Program (LEAP) as evidence of eligibility as an eligible low-income CSG subscriber in a CSG.

(B) Acquisition of energy and RECs from eligible low-income CSG subscribers to CSGs may be either through dedicated low-income CSGs or low-income set asides within other CSGs.

(V) For investments in a new CSG, the investor owned QRU shall be eligible for the incentives and be subject to the ownership limitations set forth in rule 3660; however such incentive payments shall be excluded from the retail rate impact under rule 3661.

(VI) The investor owned QRU may file an application with the Commission for approval to recover through rates a margin on renewable energy and RECs purchased from CSGs; however such incentive payments shall be excluded from the retail rate impact under rule 3661.

(VII) Notwithstanding the exclusion from the retail rate impact in subparagraphs 3665(d)(VI) and (VII), the acquisition of renewable energy and RECs from CSGs shall be subject to the retail rate impact under rule 3661. QRU expenditures for unsubscribed energy and RECs generated by CSGs shall be included in the calculations of retail rate impact under that rule.

(e) Financing and operating CSGs.

(I) Contracts signed by QRUs with CSG owners shall be a matter of public record and shall be filed with the Commission by the QRU.

(II) CSG subscriber organizations shall issue public annual reports as of the end of the calendar or other fiscal year containing, at a minimum, the energy produced by the CSG; audited financial statements including a balance sheet, income statement, and sources and uses of funds statement; and the management and ownership of the CSG and the CSG subscriber organization, if different. Individual subscribers shall receive, in addition to the annual report of the CSG subscriber organization, a report of the energy, multiplier (e.g., aggregate retail rate), and net metering credits attributed to the CSG subscriber's account.

(III) CSG subscriber funds, collected by the CSG in advance of commercial operation of the CSG, shall be held in escrow. The escrow shall be maintained by its terms until such time as the CSG commences commercial operation as certified by QRU acceptance of energy from the CSG.

3666. Rural Renewable Projects.

(a) QRUs may take advantage of REC multiplier for rural renewable projects described in paragraph 3654(h) subject to the following restrictions.

(I) Interconnection must be completed and commercial operation achieved by December 31, 2014.

(II) For investor owned QRUs, rural renewable projects for which this REC multiplier is claimed may not be counted toward the distributed generation requirements in rule 3655.

(III) Any entity that owns or develops a rural renewable project that will take advantage of the aforementioned compliance multiplier, must notify the Commission on a Commission-provided form within 30 days after signing a power purchase agreement with a QRU and also within 30 days after beginning commercial operations. Such forms will minimally require the MW of nameplate electric capacity from installed rural renewable projects or the capacity that is subject to power purchase agreements, as applicable.

(IV) For QRUs that are not investor owned QRUs, the compliance multiplier may be applied only to the aggregate first 100 MW of nameplate capacity projects statewide that report having achieved commercial operation to the Commission.

(V) The Commission will maintain a publicly available listing of projects that have submitted notifications in accordance with subparagraph 3666(a)(III) and shall provide notice to the first 100 MW of projects that are providing energy and RECs to non-investor owned QRUs that they may take advantage of the compliance multiplier.

3667. Small Generation Interconnection Procedures.

The following small generator interconnection procedures (SGIP) shall apply to all small generation resources including eligible renewable energy resources connected to the utility. Each utility shall also provide, on its web site, interconnection standards not included in these procedures. This rule largely tracks FERC Order 2006.

(a) Definitions. The following definitions apply only to rule 3665.

(I) “Business day” means Monday through Friday, excluding Federal Holidays.

(II) “Distribution system” means the utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

(III) “Distribution upgrades” means the additions, modifications, and upgrades to the utility's distribution system at or beyond the point of interconnection to facilitate interconnection of the small generating facility and render the service necessary to effect the interconnection customer's operation of on-site generation. Distribution upgrades do not include interconnection facilities.

(IV) “Highly seasonal circuit” means a circuit with a ratio of annual peak load to off-season peak load greater than six.

(V) “Interconnection customer” or “IC” means any entity, including the utility, any affiliates or subsidiaries of either, that proposes to interconnect its small generating facility with the utility's system.

(VI) “Interconnection facilities” means the utility's interconnection facilities and the interconnection customer's interconnection facilities. Collectively, interconnection facilities include all facilities and equipment between the small generating facility and the point of interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the small generating facility to the utility's system. Interconnection facilities are sole use facilities and shall not include distribution upgrades.

(VII) “Interconnection request” means the interconnection customer's request, in accordance with any applicable utility tariff, to interconnect a new small generating facility, or to increase the capacity of, or make a material modification to the operating characteristics of, an existing small generating facility that is interconnected with the utility’s system.

(VIII) “Minimum daytime loading” means the lowest daily peak in the year on the line section.

(IX) “Party” or “Parties” means the utility, interconnection customer, or any combination of the above.

(X) "Point of interconnection" means the point where the Interconnection facilities connect with the utility's system.

(XI) "Small generating facility" means the interconnection customer's device for the production of electricity identified in the interconnection request, but shall not include the interconnection facilities not owned by the interconnection customer.

(XII) "Study process" means the procedure for evaluating an interconnection request that includes the Level 3 scoping meeting, feasibility study, system impact study, and facilities study.

(XIII) "System" means the facilities owned, controlled, or operated by the utility that are used to provide electric service under the tariff.

(XIV) "Upgrades" means the required additions and modifications to the utility's system at or beyond the point of interconnection. Upgrades do not include interconnection facilities.

(b) General overview.

(I) Applicability.

(A) A request to interconnect a certified small generating facility no larger than two MW shall be evaluated under the Level 2 Process. A request to interconnect a certified inverter-based small generating facility no larger than ten kW shall be evaluated under the Level 1 Process. A request to interconnect a small generating facility larger than two MW but no larger than ten MW or a small generating facility that does not pass the Level 1 or Level 2 Process, shall be evaluated under the Level 3 Process.

(B) Defined terms used herein shall have the meanings specified in the paragraph (a) of this rule.

(C) Prior to submitting its interconnection request, the interconnection customer may ask the utility interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The utility shall respond within 15 business days.

(D) Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects all utilities, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

(E) References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

(II) Pre-application. The utility shall designate an employee or office from which information on the application process and on an affected system can be obtained through informal requests from the interconnection customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the utility's Internet web site. Electric system information for specific locations, feeders, or small areas shall be provided to the interconnection customer upon request and may include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the utility's system, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The utility shall comply with reasonable requests for such information unless such information is proprietary or confidential and cannot be provided pursuant to a confidentiality agreement.

(III) Interconnection request. The interconnection customer shall submit its interconnection request to the utility, together with the processing fee or deposit specified in the interconnection request. The interconnection request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the interconnection request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The interconnection customer shall be notified of receipt by the utility within three business days of receiving the interconnection request which notification may be to an e-mail address or fax number provided by IC. The utility shall notify the interconnection customer within ten business days of the receipt of the interconnection request as to whether the interconnection request is complete or incomplete. If the interconnection request is incomplete, the utility shall provide, along with the notice that the interconnection request is incomplete, a written list detailing all information that must be provided to complete the interconnection request. The interconnection customer will have ten business days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the IC does not provide the listed information or a request for an extension of time within the deadline, the interconnection request will be deemed withdrawn. An interconnection request will be deemed complete upon submission of the listed information to the utility.

(IV) Modification of the interconnection request. Any modification to machine data or equipment configuration or to the interconnection site of the small generating facility not agreed to in writing by the utility and the IC may be deemed a withdrawal of the interconnection request and may require submission of a new interconnection request, unless proper notification of each party by the other and a reasonable time to cure the problems created by the changes are undertaken.

(V) Site control. Documentation of site control must be submitted with the interconnection request. Site control may be demonstrated through:

(A) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the small generating facility;

(B) an option to purchase or acquire a leasehold site for such purpose; or

(C) an exclusivity or other business relationship between the IC and the entity having the right to sell, lease, or grant the IC the right to possess or occupy a site for such purpose.

(VI) Queue position. The utility shall place interconnection requests in a first come, first served order per feeder and per substation based upon the date- and time-stamp of the interconnection request. The order of each interconnection request will be used to determine the cost responsibility for the upgrades necessary to accommodate the interconnection. At the utility's option, interconnection requests may be studied serially or in clusters for the purpose of the system impact study.

(VII) Assignment/Transfer of ownership of the facility. Interconnection agreements shall survive transfer of ownership of the generating facility to a new owner when the new owner agrees in writing to comply with the terms of the agreement and so notifies the utility.

(c) Level 2 - fast track process.

(I) Applicability. The fast track process is available to an IC proposing to interconnect its small generating facility with the utility's system if the small generating facility is no larger than two MW and if the IC’s proposed small generating facility meets the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures.

(II) Initial review. Within 15 business days after the utility notifies the interconnection customer it has received a complete interconnection request, the utility shall perform an initial review using the screens set forth below, shall notify the interconnection customer of the results, and include with the notification copies of the analysis and data underlying the utility's determinations under the screens.

(A) Screens.

(i) The proposed small generating facility’s point of interconnection must be on a portion of the utility’s distribution system that is subject to the tariff.

(ii) For interconnection of a proposed small generating facility to a radial distribution circuit, the aggregated generation, including the proposed small generating facility, on the line section shall not exceed 15 percent of the line section’s annual peak load as most recently measured at the substation or calculated for the line section. For highly seasonal circuits only, the aggregate generation, including the proposed small generation facility, on the line section shall not exceed 15 percent of two times the minimum daytime loading. A line section is that portion of a utility’s electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. A fuse is not an automatic sectionalizing device.

(iii) The proposed small generating facility, in aggregation with other generation on the distribution circuit, shall not contribute more than ten percent to the distribution circuit's maximum fault current at the point on the distribution feeder voltage (primary) level nearest the proposed point of change of ownership.

(iv) The proposed small generating facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 percent of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 percent of the short circuit interrupting capability.

(v) The proposed small generating facility shall have a starting voltage dip less than five percent and meet the flicker requirements of IEEE 519, 1992 version. To meet this screen, the proposed generating facility must conform to the following two tests:

(1) For starting voltage dip, the utility has two options for determining whether starting voltage dip is acceptable. The option to be used is at the utility's discretion.

(a) Option 1: The utility may determine that the proposed generating facility's starting in-rush current is equal to or less than the continuous ampere rating of the Interconnection Customer's service equipment.

(b) Option 2: The utility may determine the impedances of the service distribution transformer (if present) and the secondary conductors to the Interconnection Customer's service equipment and perform a voltage dip calculation. Alternatively, the utility may use tables or nomographs to determine the voltage dip. Voltage dips caused by starting the proposed generation facility must be less than five percent when measured at the primary side (high side) of a dedicated distribution transformer serving the proposed generating facility, for primary interconnections. The five percent voltage dip limit applies to the distribution transformer low side if the low side is shared with other customers and to the high side if the transformer is dedicated to the Interconnection Customer.

(2) The second test is conformance with the relationship between voltage fluctuation and starting frequency presented in the table for flicker requirements in IEEE 519, 1992 version.

(vi) Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the IC, including line configuration and the transformer connection to limit the potential for creating over-voltages on the utility's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

(vii) If the proposed small generating facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed small generating facility, shall not exceed 20 kW.

(viii) If the proposed small generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 percent of the nameplate rating of the service transformer.

(ix) No construction of facilities by the utility on its own system shall be required to accommodate the small generating facility.

(x) Interconnections to distribution networks.

(1) For interconnection of a proposed small generating facility to the load side of spot network protectors serving more than a single customer, the proposed small generating facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of five percent of a spot network's maximum load or 300 kW. For spot networks serving a single customer, the small generator facility must use inverter-based equipment package and either meet the requirements above or shall use a protection scheme or operate the generator so as not to exceed on-site load or otherwise prevent nuisance operation of the spot network protectors.

(2) For interconnection of a proposed small generating facility to the load side of area network protectors, the proposed small generating facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of ten percent of an area network's minimum load or 500 kW.

(3) Notwithstanding sub-sections (1) or (2) above, each utility may incorporate into its interconnection standards, any change in interconnection guidelines related to networks pursuant to standards developed under IEEE 1547 for interconnections to networks. To the extent the new IEEE standards conflict with these existing guidelines, the new standards shall apply. In addition, and with the consent of the utility, a small generator facility may be interconnected to a spot or area network provided the facility uses a protection scheme that will prevent any power export from the customer’s site including inadvertent export under fault conditions or otherwise prevent nuisance operation of the network protectors.

(B) If the proposed interconnection passes the screens, the interconnection request shall be approved and the utility will provide the IC an executable interconnection agreement within five business days after the determination.

(C) If the proposed interconnection fails the screens, but the utility determines that the small generating facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the utility shall provide the IC an executable interconnection agreement within five business days after the determination.

(D) If the proposed interconnection fails the screens, but the utility does not or cannot determine from the initial review that the small generating facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the IC is willing to consider minor modifications or further study, the utility shall provide the IC with the opportunity to attend a customer options meeting.

(E) Customer options meeting. If the utility determines the interconnection request cannot be approved without minor modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five business day period after the determination, the utility shall notify the IC and provide the data and analyses underlying its conclusion. Within ten business days of the utility's determination, the utility shall offer to convene a customer options meeting with the utility to review possible IC facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the small generating facility to be connected safely and reliably. At the time of notification of the utility's determination, or at the customer options meeting, the utility shall:

(i) offer to perform facility modifications or minor modifications to the utility's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the utility's electric system;

(ii) offer to perform a supplemental review if the utility concludes that the supplemental review might determine that the small generating facility could continue to qualify for interconnection pursuant to the fast track process, and provide a non-binding good faith estimate of the costs and time of such review; or

(iii) obtain the interconnection customer's agreement to continue evaluating the interconnection request under the Level 3 Study Process.

(III) Supplemental Review. If the interconnection customer agrees to a supplemental review, the interconnection customer shall agree in writing within 15 business days of the offer, and submit a deposit for the estimated costs provided in subsection (c)(III)(A)(ii) of this rule. The IC shall be responsible for the utility's actual costs for conducting the supplemental review. The IC must pay any review costs that exceed the deposit within 20 business days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the utility will return such excess within 20 business days of the invoice without interest.

(A) Within ten business days following receipt of the deposit for a supplemental review, the utility will determine if the Small Generating Facility can be interconnected safely and reliably.

(i) If so, the utility shall forward an executable interconnection agreement to the IC within five business days.

(ii) If so, and IC facility modifications are required to allow the small generating facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the utility shall forward an executable interconnection agreement to the IC within five business days after confirmation that the interconnection customer has agreed to make the necessary changes at the interconnection customer's cost.

(iii) If so, and minor modifications to the utility's electric system are required to allow the small generating facility to be interconnected consistent with safety, reliability, and power quality standards under the Level 2 Fast Track Process, the utility shall forward an executable interconnection agreement to the IC within ten business days that requires the IC to pay the costs of such system modifications prior to interconnection.

(iv) If not, the interconnection request will continue to be evaluated under the Level 3 Study Process.

(d) Level 3 - Study Process.

(I) Applicability. The study process shall be used by an interconnection customer proposing to interconnect its small generating facility with the utility's system if the small generating facility is larger than two MW but no larger than ten MW; is not certified; or, is certified but did not pass the Fast Track Process or the ten kW Inverter Process.

(II) Scoping meeting.

(A) A scoping meeting will be held within ten business days after the interconnection request is deemed complete, or as otherwise mutually agreed to by the parties. The utility and the interconnection customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

(B) The purpose of the scoping meeting is to discuss the interconnection request. The parties shall further discuss whether the utility should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the parties agree that a feasibility study should be performed, the utility shall provide the IC, as soon as possible, but not later than five business days after the scoping meeting, a feasibility study agreement including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(C) The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an IC who has requested a feasibility study must return the executed feasibility study agreement within 15 business days. If the parties agree not to perform a feasibility study, the utility shall provide the IC, no later than five business days after the scoping meeting, a system impact study agreement including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(D) Feasibility studies, scoping studies, and facility studies may be combined for simpler projects by mutual agreement of the utility and the parties.

(III) Feasibility study.

(A) The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the small generating facility.

(B) A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the interconnection customer.

(C) The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement.

(D) If the feasibility study shows no potential for adverse system impacts, the utility shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(E) If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

(IV) System impact study.

(A) A system impact study shall identify and detail the electric system impacts that would result if the proposed small generating facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

(B) If no transmission system impact study is required, but potential electric power distribution system adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The utility shall send the IC a distribution system impact study agreement within 15 business days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

(C) In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five business days following transmittal of the feasibility study report, the utility shall send the IC a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

(D) If a transmission system impact study is not required, but electric power distribution system adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the utility shall send the IC a distribution system impact study agreement.

(E) If the feasibility study shows no potential for transmission system or distribution system adverse system impacts, the utility shall send the IC either a facilities study agreement, including an outline of the scope of the study and a non binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

(F) In order to remain under consideration for interconnection, the IC must return executed system impact study agreements, if applicable, within 30 business days.

(G) A deposit of the good faith estimated costs for each system impact study may be required from the IC.

(H) The scope of and cost responsibilities for a system impact study are described in the system impact study agreement.

(I) Where transmission systems and distribution systems have separate owners, such as is the case with transmission-dependent utilities (TDUs) – whether investor-owned or not – the IC may apply to the nearest utility (Transmission Owner, Regional Transmission Operator, or Independent utility) providing transmission service to the TDU to request project coordination. Affected systems shall participate in the study and provide all information necessary to prepare the study.

(V) Facilities study.

(A) Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the IC along with a facilities study agreement within five business days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the IC within the same timeframe.

(B) In order to remain under consideration for interconnection, or, as appropriate, in the utility's interconnection queue, the IC must return the executed facilities study agreement or a request for an extension of time within 30 business days.

(C) The facilities study shall specify and estimate the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

(D) Design for any required interconnection facilities and/or upgrades shall be performed under the facilities study agreement. The utility may contract with consultants to perform activities required under the facilities study agreement. The IC and the utility may agree to allow the IC to separately arrange for the design of some of the interconnection facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the utility, under the provisions of the facilities study agreement. If the parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the utility shall make sufficient information available to the IC in accordance with confidentiality and critical infrastructure requirements to permit the IC to obtain an independent design and cost estimate for any necessary facilities.

(E) A deposit of the good faith estimated costs for the facilities study may be required from the IC.

(F) The scope of and cost responsibilities for the facilities study are described in a facilities study agreement.

(G) Upon completion of the facilities study, and with the agreement of the IC to pay for interconnection facilities and upgrades identified in the facilities study, the utility shall provide the IC an executable interconnection agreement within five business days.

(e) Provisions that apply to all interconnection requests.

(I) Reasonable efforts. The utility shall make reasonable efforts to meet all time frames provided in these procedures unless the utility and the IC agree to a different schedule. If the utility cannot meet a deadline provided herein, it shall notify the IC explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

(II) Disputes.

(A) The parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

(B) In the event of a dispute, either party shall provide the other party with a written notice of dispute. Such notice shall describe in detail the nature of the dispute. If the dispute has not been resolved within five business days after receipt of the notice, either party may contact a mutually agreed upon third party dispute resolution service for assistance in resolving the dispute.

(C) The dispute resolution service will assist the parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the parties in resolving their dispute.

(D) Each party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

(E) If neither party elects to seek assistance from the dispute resolution service, or if the attempted dispute resolution fails, then either party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of the agreements between the parties or it may seek resolution at the Commission.

(III) Interconnection metering. Except as otherwise required by rule 3664, any metering necessitated by the use of the small generating facility shall be installed at the IC's expense in accordance with Commission requirements or the utility's specifications.

(IV) Commissioning tests. Commissioning tests of the IC's installed equipment shall be performed pursuant to applicable codes and standards, including IEEE1547.1 2005 "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems". The utility must be given at least five business days written notice, or as otherwise mutually agreed to by the parties, of the tests and may be present to witness the commissioning tests. The utility shall be compensated by the IC for its expense in witnessing level 2 and Level 3 commissioning tests. The utility shall provide to the IC an operational approval letter within three business days after notification that the commissioning test has been successfully completed. Such letter may be provided via e-mail.

(V) Confidentiality.

(A) Confidential information shall mean any confidential and/or proprietary information provided by one party to the other party that is clearly marked or otherwise designated "Confidential." All design, operating specifications, and metering data provided by the IC shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

(B) Confidential information does not include information previously in the public domain, required to be publicly submitted or divulged by governmental authorities (after notice to the other party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce an agreement between the parties. Each party receiving confidential information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the party providing that information, except to fulfill obligations under agreements between the parties, or to fulfill legal or regulatory requirements.

(i) Each party shall employ at least the same standard of care to protect confidential information obtained from the other party as it employs to protect its own confidential information.

(ii) Each party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of confidential information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

(C) Notwithstanding anything in this article to the contrary, if the Commission, during the course of an investigation or otherwise, requests information from one of the parties that is otherwise required to be maintained in confidence, the party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the party may request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other party prior to the release of the confidential information to the Commission. The party shall notify the other party when it is notified by the Commission that a request to release confidential information has been received by the Commission, at which time either of the parties may respond before such information would be made public.

(VI) Comparability. The utility shall receive, process, and analyze all interconnection requests in a timely manner as set forth in this document. The utility shall use the same reasonable efforts in processing and analyzing interconnection requests from all interconnection customers, whether the small generating facility is owned or operated by the utility, its subsidiaries or affiliates, or others.

(VII) Record retention. The utility shall maintain for three years records, subject to audit, of all interconnection requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the interconnection requests.

(VIII) Interconnection agreement. After receiving an interconnection agreement from the utility, the IC shall have 30 business days or another mutually agreeable time-frame to sign and return the interconnection agreement, or request that the utility file an unexecuted interconnection agreement with the Commission. If the IC does not sign the interconnection agreement, or ask that it be filed unexecuted by the utility within 30 business days, the interconnection request shall be deemed withdrawn. After the interconnection agreement is signed by the parties, the interconnection of the small generating facility shall proceed under the provisions of the interconnection agreement.

(IX) Coordination with affected systems. The utility shall coordinate the conduct of any studies required to determine the impact of the interconnection request on affected systems with affected system operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The utility will include such affected system operators in all meetings held with the IC as required by these procedures. The IC will cooperate with the utility in all matters related to the conduct of studies and the determination of modifications to affected systems. A utility which may be an affected system shall cooperate with the utility with which interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to affected systems.

(X) Capacity of the small generating facility.

(A) If the interconnection request is for an increase in capacity for an existing small generating facility, the interconnection request shall be evaluated on the basis of the new total capacity of the small generating facility.

(B) If the interconnection request is for a small generating facility that includes multiple energy production devices at a site for which the interconnection customer seeks a single point of interconnection, the interconnection request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

(C) The interconnection request shall be evaluated using the maximum rated capacity of the small generating facility.

(XI) Insurance.

(A) For systems of ten kW or less, the customer, at its own expense, shall secure and maintain in effect during the term of the agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $300,000 for each occurrence. For systems above ten kW and up to 500 kW, customer, at its own expense, shall secure and maintain in effect during the term of the agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $1,000,000 for each occurrence. For systems above 500 kW and up to two MW, customer, at its own expense, shall secure and maintain in effect during the term of the agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $2,000,000 for each occurrence. Insurance coverage for systems greater than two MW shall be determined on a case-by-case basis by the utility and shall reflect the size of the installation and the potential for system damage.

(B) For systems over 500 kW, the utility shall be named as an additional insured by endorsement to the insurance policy and the policy shall provide that written notice be given to the utility at least 30 days prior to any cancellation or reduction of any coverage. Such liability insurance shall provide, by endorsement to the policy, that the utility shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium of such insurance. For all solar systems, the liability insurance shall not exclude coverage for any incident related to the subject generator or its operation.

(C) Certificates of Insurance evidencing the requisite coverage and provision(s) shall be furnished to utility prior to the date of interconnection of the generation system. Utilities shall be permitted to periodically obtain proof of current insurance coverage form the generating customer in order to verify proper liability insurance coverage. Customer will not be allowed to commence or continue interconnected operations unless evidence is provided that satisfactory insurance coverage is in effect at all times.

(f) Level 1 ten kW inverter process. The procedure for evaluating an interconnection request for a certified inverter-based small generating facility no larger than ten kW. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions.

(I) The interconnection customer (customer) completes the interconnection request (Application) and submits it to the utility.

(II) The utility acknowledges to the customer receipt of the application within three business days of receipt.

(III) The utility evaluates the application for completeness and notifies the customer within ten business days of receipt that the application is or is not complete and, if not, advises what material is missing.

(IV) Within 15 days the utility shall conduct an initial review, which shall include the following screening criteria.

(A) For interconnection of a proposed small generating facility to a radial distribution circuit, the aggregated generation, including the proposed small generating facility, on the line section shall not exceed 15 percent of the line section annual peak load as most recently measured at the substation or calculated for the line section. For highly seasonal circuits only, the aggregate generation, including the proposed small generation facility, on the line section shall not exceed 15 percent of two times the minimum daytime loading. A line section is that portion of a utility's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. A fuse is not an automatic sectionalizing device.

(B) If the proposed small generating facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed small generating facility, shall not exceed 20 kW.

(C) If the proposed small generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 percent of the nameplate rating of the service transformer.

(D) No construction of facilities by the utility on its own system shall be required to accommodate the small generating facility.

(E) Provided all the criteria in paragraph (g) of this rule are met, unless the utility determines and demonstrates that the small generating facility cannot be interconnected safely and reliably, the utility approves and executes the application and returns it to the customer.

(F) After installation, the customer returns the certificate of completion to the utility. Prior to parallel operation, the utility may inspect the small generating facility for compliance with standards, which may include a witness test, and may schedule appropriate metering replacement, if necessary.

(G) The utility notifies the customer in writing or by fax or e-mail that interconnection of the small generating facility is authorized within five business days. If the witness test is not satisfactory, the utility has the right to disconnect the small generating facility. The customer has no right to operate in parallel until a witness test has been performed, or previously waived on the application. The utility is obligated to complete this witness test within ten business days of the receipt of the certificate of completion.

(H) Contact information. The customer must provide the contact information for the legal applicant (i.e., the interconnection customer). If another entity is responsible for interfacing with the utility, that contact information must be provided on the application.

(g) Level 1 10 kW Inverter Process. The following constitutes an application for interconnecting a certified inverter-based small generating facility no larger than ten KW. Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the application may be required.

Processing fee:

A fee of ____________ must accompany this application.

Interconnection customer

Name:

Contact Person:

Address:

City: State: Zip:

Telephone (Day): (Evening):

Fax: E-Mail Address:

Engineering firm (If applicable):

Contact Person:

Address:

City: State: Zip:

Telephone:

Fax: E-Mail Address:

Contact (if different from Interconnection customer):

Name:

Address:

City: State: Zip:

Telephone (Day): (Evening):

Fax: E-Mail Address:

Owner of the facility (include percent ownership by any electric utility):

Small generating facility information:

Location (if different from above):

Electric service company:

Account number:

Small generator ten kW inverter process:

Inverter manufacturer: ___________Model

Nameplate rating: (kW) (kVA) (AC Volts)

Single phase _______ Three phase_______

System design capacity: _________ (kW) _______ (kVA)

Prime mover: Photovoltaic Reciprocating Engine Fuel Cell Turbine Other

Energy source: Solar Wind Hydro Diesel Natural Gas Fuel Oil Other (describe)

Is the equipment UL1741 Listed? Yes ____ No ____

If Yes, attach manufacturer's cut-sheet showing UL1741 listing.

Estimated installation date: _____________ Estimated in-service date: ____________

The ten kW inverter process is available only for inverter-based small generating facilities no larger than ten kW that meet the codes, standards, and certification requirements of paragraphs (h) and (i) of this rule, or the QRU has reviewed the design or tested the proposed small generating facility and is satisfied that it is safe to operate.

List components of the small generating facility equipment package that are currently certified:

Equipment type certifying entity:

1.

2.

3.

4.

5.

Interconnection customer signature: _________________________

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: Date:

Contingent approval to interconnect the small generating facility.

(For company use only)

Interconnection of the small generating facility is approved contingent upon the terms and conditions for interconnecting an inverter-based small generating facility no larger than ten kW and return of the certificate of completion.

Company signature: ____

Title: Date:

Application ID number: _________________

Company waives inspection/witness test? Yes ____ No ____

(h) Certification codes and standards.

ANSI C84.1-2011 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

ANSI/NEMA MG 1--2011, Motors and Generators

IEEE Std C37.90.1-2002, IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2-2004, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-2002, IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2005, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002/Cor 1-2012, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

IEEE Std 100-2000, The Authoritative Dictionary of IEEE Standards Terms, Seventh Edition

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

IEEE Std 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

IEEE Std 547.1-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

NFPA 70 (2014), National Electrical Code

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

(i) Certification of small generator equipment packages.

(I) Small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in paragraph (h); it has been labeled and is publicly listed by such NRTL at the time of the interconnection application; and, such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

(II) The interconnection customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

(III) Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

(IV) If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

(V) Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

(VI) An equipment package does not include equipment provided by the utility.

(j) Terms and conditions for Level 1 interconnections -- small generating facility no larger than ten kW.

(I) Construction of the facility. The interconnection customer may proceed to construct the small generating facility when the utility approves the interconnection request (the application) and returns it to the IC.

(II) Interconnection and operation. The IC may operate small generating facility and interconnect with the utility's electric system once all of the following have occurred:

(A) upon completing construction, the interconnection customer will cause the small generating facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction;

(B) the customer returns the certificate of completion to the utility; and

(C) the utility has completed its inspection of the small generating facility. All inspections must be conducted by the utility, at its own expense, within ten business days after receipt of the certificate of completion and shall take place at a time agreeable to the parties. The utility shall provide a written statement that the small generating facility has passed inspection or shall notify the customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place.

(D) The utility has the right to disconnect the small generating facility in the event of improper installation or failure to return the certificate of completion.

(III) Safe operations and maintenance. The interconnection customer shall be fully responsible to operate, maintain, and repair the small generating facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

(IV) Access. The utility shall have access to the disconnect switch and metering equipment of the small generating facility at all times. The utility shall provide reasonable notice to the customer when possible prior to using its right of access.

(V) Disconnection. The utility may temporarily disconnect the small generating facility upon the following conditions:

(A) for scheduled outages per notice requirements in the utility’s tariff or Commission rules;

(B) for unscheduled outages or emergency conditions pursuant to the utility’s tariff or Commission rules; or

(C) if the small generating facility does not operate in the manner consistent with these terms and conditions.

(D) The utility shall inform the interconnection customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

(VI) Indemnification. The parties shall at all times indemnify, defend, and save the other party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other party's action or inactions of its obligations under this agreement on behalf of the indemnifying party, except in cases of gross negligence or intentional wrongdoing by the indemnified party.

(VII) Insurance. The interconnection customer, at its own expense, shall secure and maintain in effect during the term of this agreement, liability insurance with a combined single limit for bodily injury and property damage of not less than $300,000 each occurrence. Such liability insurance shall not exclude coverage for any incident related to the subject generator or its operation. The utility shall be named as an additional insured under the liability policy unless the system is a solar system installed on a premise using the residential tariff and has a design capacity of ten kW or less. The policy shall include that written notice be given to the utility at least 30 days prior to any cancellation or reduction of any coverage. A copy of the liability insurance certificate must be received by the utility prior to plant operation. Certificates of insurance evidencing the requisite coverage and provision(s) shall be furnished to utility prior to date of interconnection of the generation system. Utilities shall be permitted to periodically obtain proof of current insurance coverage from the generating customer in order to verify proper liability insurance coverage. The interconnection customer will not be allowed to commence or continue interconnected operations unless evidence is provided that satisfactory insurance coverage is in effect at all times.

(VIII) Limitation of liability. Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under subparagraph (i)(VI) of this rule.

(IX) Termination. The agreement to operate in parallel may be terminated under the following conditions.

(A) By the customer by providing written notice to the utility.

(B) By the utility if the small generating facility fails to operate for any consecutive 12 month period or the customer fails to remedy a violation of these terms and conditions.

(C) Permanent disconnection. In the event this agreement is terminated, the utility shall have the right to disconnect its facilities or direct the customer to disconnect its small generating facility.

(D) Survival rights. This agreement shall continue in effect after termination to the extent necessary to allow or require either party to fulfill rights or obligations that arose under the agreement.

(X) Assignment/Transfer of ownership of the facility. This agreement shall survive the transfer of ownership of the small generating facility to a new owner when the new owner agrees in writing to comply with the terms of this agreement and so notifies the utility.

3668. Environmental Impacts.

(a) Eligible energy resources must meet all applicable federal, state, and local environmental permitting requirements.

(b) For eligible energy resources larger than two MW that are not net-metered or any wind turbine structures extending over 50 feet in height, the QRU shall require project developers to include in the bid package written documentation that consultation occurred with appropriate governmental agencies (for example, the Colorado Division of Wildlife or the U.S. Fish and Wildlife Service) responsible for reviewing potential project development impacts to state and federally listed wildlife species, as well as species, habitats, and ecosystems of concern.

(c) For eligible energy resources larger than two MW that are not net-metered or any wind turbine structures extending over 50 feet in height, the QRU renewable energy supply contract shall require project developers to certify the following as a condition precedent to achieving commercial operation:

(I) the developer has performed site specific wildlife surveys (referred to herein as the Environmental Surveys) which are conducted on the facility's site prior to construction;

(II) the developer, with good faith effort, used the results of the Environmental Surveys and available monitoring in developing the design, construction plans, and management plans of the facilities to avoid, minimize, and/or mitigate any adverse environmental impacts to state and federally listed species, to species of special concern, to sites shown to be local bird migration pathways, to critical habitat, to important ecosystems, and to areas where birds or other wildlife are highly concentrated and are considered at risk;

(III) the results of the pre-construction Environmental Surveys shall be shared with the Colorado Division of Wildlife (CDOW) prior to project construction; and

(IV) a summary report of these results shall be made available to CDOW at the time the project achieves commercial operation.

(d) The Commission shall determine whether the electricity generated by coal mine methane or a synthetic gas is greenhouse gas (GHG) neutral on a case-by-case basis, measuring greenhouse gasses in terms of carbon dioxide equivalent.

3669. – 3699. [Reserved].

APPEALS OF LOCAL GOVERNMENT LAND USE DECISIONS

3700. Scope and Applicability.

Rules 3700 through 3707 apply to all utilities or power authorities which seek to appeal a local government action concerning a major electrical facility.

3701. Definitions.

The following definitions apply to rules 3700 through 3707, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Local government" means a county, a home rule or statutory city, town, a territorial charter city, a or city and county.

(b) "Local government action" means (1) any decision, in whole or in part, by a local government which has the effect or result of denying a permit or application of a utility or power authority that relates to the location, construction, or improvement of a major electrical facility or (2) a decision which imposes requirements or conditions upon such permit or application that will unreasonably impair the ability of the utility or power authority to provide safe, reliable, and economical service to the public.

(c) "Local land use decision" means the decision of a local government within its jurisdiction to plan for and regulate the use of land.

(d) "Major electrical facility" shall have that meaning set forth in § 29-20-108(3)(a), (b), (c), and (d), C.R.S., or in any other applicable statute.

(e) "Power authority" means an authority created pursuant to § 29-1-204, C.R.S.

3702. Precondition to Application.

In order for a utility or power authority to appeal a local government action to the Commission pursuant to this rule and pursuant to § 29-20-108, C.R.S., one or more of the following conditions must be met:

(a) the utility or power authority has applied for or has obtained a certificate of public convenience and necessity from the Commission pursuant to § 40-5-101, C.R.S., to construct the major electrical facility that is the subject of the local government action;

(b) a certificate of public convenience and necessity is not required for the utility or power authority to construct the major electrical facility that is the subject of the local government action; or

(c) the Commission has previously entered an order pursuant to § 40-4-102, C.R.S., that conflicts with the local government action.

3703. Applications.

(a) To commence an appeal of a local government land use decision, a utility or power authority shall file with the Commission an application pursuant to this rule.

(b) An application filed in accordance with §§ 29-20-108, C.R.S., and this rule shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) all of information required in paragraphs 3002(b) and 3002(c);

(II) a showing that one of the preconditions set out in rule 3702 has been met;

(III) identification of the major electrical facility;

(IV) identification of the local government action and its impact on the major electrical facility;

(V) a statement of the reasons the applying utility or power authority believes that the local government action would unreasonably impair its ability to provide safe, reliable, and economical service to the public;

(VI) the demonstrated need for the major electrical facility or reference to the application made to the Commission with respect to the major electrical facility and the resulting decision of the Commission regarding such facility;

(VII) the extent to which the proposed facility is inconsistent with existing applicable local or regional land use ordinances, resolutions, or master or comprehensive plans;

(VIII) whether the proposed facility would exacerbate a natural hazard;

(IX) applicable utility engineering standards, including supply adequacy, system reliability, and public safety standards;

(X) the relative merit, as determined through use of the normal system planning evaluation techniques of the utility or power authority, of any reasonably available and economically feasible alternatives proposed by the utility, the power authority, or the local government;

(XI) the impact that the local government action would have on the customers of the utility or power authority who reside within and without the boundaries of the jurisdiction of the local government;

(XII) the basis for the local government action. If available, the utility or power authority shall attach a copy of the local government action;

(XIII) the impact the proposed facility would have on residents within the local government's jurisdiction including, in the case of a right-of-way in which facilities have been placed underground, whether those residents have already paid to place such facilities underground. If the residents have already paid to place facilities underground, the Commission will give strong consideration to that fact;

(XIV) information concerning how the proposed major electrical facility will affect the safety of residents within and without the boundaries of the jurisdiction of the local government; and

(XV) an attestation that the utility or power authority will, upon filing the application with the Commission, simultaneously send a copy of the application to the local government body which took the local government action which is the subject of the appeal.

3704. Public Hearing.

Pursuant to § 29-20-108(5)(b), C.R.S., and in addition to the formal evidentiary hearing on the appeal, the Commission shall take statements from the public concerning the appealed local government action at a public hearing held at a location specified by the local government.

3705. Prehearing Conference, Parties, and Public Notice.

(a) In order to assist the parties in scheduling the public hearing, determining the scheduling of the evidentiary hearing, developing the list of persons to receive notice of these hearings, and addressing other pertinent issues, the Commission will hold a prehearing conference.

(b) The Commission shall conduct a prehearing conference within 15 days after the application is deemed complete by the Commission.

(c) The Commission shall join as an indispensable party the local government which took the contested local government action.

(d) Ten days before the commencement of the prehearing conference, the local government shall submit to the parties and the Commission its preference for the location of the public hearing to be held in accordance with § 29-20-108(5)(b), C.R.S., and rule 3704.

(e) The Commission will decide the date and time of the public hearing after receiving comments from the parties at the prehearing conference.

(f) By the date of the prehearing conference, each party shall provide to the utility or power authority a list of individuals and groups to receive notice of the public hearing.

(g) The utility or power authority shall give notice of the public hearing to the identified individuals and groups in a manner specified by the Commission. Notice may be accomplished by newspaper publication, bill insert, first class mail, or any other manner deemed appropriate by the Commission.

(h) If the local government is unable to provide meeting space for the public hearing, and space needs to be acquired, then the utility or power authority shall bear any cost associated with the rental of such space for the public hearing.

(i) The parties are encouraged to confer prior to the prehearing conference to develop a schedule for the filing of testimony and the dates for the formal evidentiary hearing.

3706. Denial of Appeal.

In accordance with § 29-20-108(5)(e), C.R.S., the Commission shall deny an appeal of a local government action if the utility or power authority has failed to comply with the following notification and consultation requirements:

(a) A utility or power authority shall notify the affected local government of its plans to site a major electrical facility within the jurisdiction of the local government prior to submitting the preliminary or final permit application, but in no event later than filing a request for a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or the filing of any annual filing with the Commission that proposes or recognizes the need for construction of a new major electrical facility or the extension of an existing facility. If a utility or power authority is not required to obtain a certificate of public convenience and necessity pursuant to Article 5 of Title 40, C.R.S., or to file annually with the Commission to notify the Commission of the proposed construction of a new major electrical facility or the extension of an existing facility, the utility or power authority shall notify any affected local government of its intention to site a major electrical facility within the jurisdiction of the local government when such utility or power authority determines that it intends to proceed to permit and to construct the facility. Following such notification, the utility or power authority shall consult with the affected local governments in order to identify the specific routes or geographic locations under consideration for the site of the major electrical facility and to attempt to resolve land use issues that may arise from the contemplated permit application.

(b) In addition to its preferred alternative within its permit application, the utility or power authority shall consider and present reasonable siting and design alternatives to the local government or shall explain why no reasonable alternatives are available.

3707. Procedural Rules.

Pursuant to § 29-20-108(5)(b), C.R.S., any appeal brought by a utility or power authority under this section shall be conducted in accordance with the procedural requirements of Article 6, Title 40, C.R.S., including § 40-6-109.5, C.R.S. Evidentiary hearings on any such appeals shall be conducted in accordance with § 40-6-109, C.R.S.

3708. – 3799. [Reserved]

MASTER METERS

3800. Scope and Applicability.

These rules are applicable to any person who purchases electric service from a utility for the purpose of delivery of that service to end-users whose aggregate usage is to be measured by a master meter or other composite measurement device.

3801. Definitions.

The following definitions apply to rules 3800 through 3805, unless a specific statute or rule provides otherwise. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) “Check-meter” means a meter or other composite measurement device which is used by a master meter operator and which is used to determine electric consumption by end-users served by the master meter operator.

(b) “Master meter” means a meter or other composite measurement device which a serving utility uses to bill a master meter operator.

(c) “Master meter operator” or “MMO” means a person who purchases electric service from a serving utility for the purpose of delivering that service to end-users whose aggregate usage is measured by a master meter.

(d) “Refund” means a refund, rebate, rate reduction, or similar adjustment.

(e) “Serving utility” means the utility from which the master meter operator receives the electric service which the master meter operator then delivers to end-users.

3802. Exemption from Rate Regulation.

(a) Pursuant to § 40-1-103.5, C.R.S., and by this rule, the Commission exempts from rate regulation under Articles 1 to 7 of Title 40, C.R.S., a master meter operator which is in compliance with rules 3803 and 3804.

(b) A master meter operator which is not in compliance with rules 3803 and 3804 is subject to rate regulation under Articles 1 to 7 of Title 40, C.R.S., and shall comply with the applicable rules.

3803. Exemption Requirements.

(a) In order to retain its exemption from rate regulation, a MMO shall do the following.

    (I) As part of its billing for utility service, the MMO shall charge its end-users only the actual cost billed to the MMO by the serving utility. The MMO shall not charge end-users for any other costs (such as, without limitation, the costs of construction, maintenance, financing, administration, metering, or billing for the equipment and facilities owned by the MMO) in addition to the actual costs billed to the MMO by the serving utility.

    (II) If the MMO bills its end-users separately for service, the sum of such billings shall not exceed the amount billed to the MMO by the serving utility.

    (III) If the MMO bills its end-users separately for service, the MMO shall pass on to its end-users all refunds the MMO receives from the serving utility or otherwise.

(IV) The MMO shall establish procedures for giving notice of a refund to those who are not current end-users but who were end-users during the period for which the refund is paid.

(V) A master meter operator shall retain, for a period of not less than three years, all records of original utility billings made to the master meter operator and all records of billings made by the master meter operator to its end-users.

(b) In order to retain its exemption from rate regulation, a MMO shall not resell electricity for profit. Resale is a basis for revocation of an exemption from rate regulation.

(c) A MMO may check-meter tenants, lessees, or other persons to whom the electricity ultimately is distributed but may do so only if the following conditions are met:

(I) the check-meter is used solely for the purpose of reimbursing the MMO by means of an appropriate allocation procedure; and

(II) the MMO does not receive more than the actual amount billed to the MMO by the serving utility.

3804. Refunds.

(a) When a serving utility notifies a MMO of a refund or when a refund is otherwise made, a MMO shall notify its end-users of the refund and shall inform the end-users that they may claim the refunds within 90 days after receipt of the notice. The notification shall be made either by first-class mail with a certificate of mailing or by inclusion in any monthly or more frequent regular written communication. The MMO shall also notify former customers who were end-users during the period for which the refund is made. The MMO shall give the notice required by this paragraph within 30 days of notification about the refund or, if there is no prior notification, within 30 days of receipt of the refund.

(b) A MMO may retain any portion of a refund which rightfully belongs to the MMO.

(c) If the aggregate amount of a refund which remains unclaimed after 90 days exceeds $100, the MMO shall contribute that unclaimed amount to the energy assistance organization in accordance with rules 3410(d), (f), and (g). If the aggregate amount which remains unclaimed after 90 days does not exceed $100, the MMO may retain the aggregate amount.

(d) A MMO shall pay interest on undistributed refunds in accordance with paragraph 3410(d).

3805. Complaints, Penalties, and Revocation of Exemption.

(a) Pursuant to rules 1301 and 1302, a person (including without limitation anyone subject to a master meter) may make an informal complaint to the External Affairs section of the Commission or may file a formal complaint with the Commission with the respect to an alleged violation of rules 3803 and 3804.

(b) As a result of a complaint or on its own motion, the Commission will investigate complaints concerning MMOs. If the Commission determines after investigation that an MMO has violated any of the requirements of rules 3803 and 3804, the MMO may have its exempt status revoked or may be subject to penalties as set forth in § 40-7-107, C.R.S., or both.

3806. – 3899. [Reserved].

SMALL POWER PRODUCERS AND COGENERATORS

3900. Scope and Applicability.

Rules 3900 through 3954 apply to utilities which purchase power from small power producers and cogenerators. These rules also apply to small power producers and cogenerators which sell power to utilities. However, for qualifying facilities with a nameplate rating of 10MW or less, to the extent that rules 3900 through 3954 are inconsistent with rule 3667, rule 3667 shall control.

3901. Definitions.

The following definitions apply to rules 3900 through 3954, except where a specific rule or statute provides otherwise. In addition to the definitions stated here, the definitions found in the Public Utilities Law, in the Public Utility Regulatory Policies Act of 1978, and in the federal regulations which are incorporated by reference apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Avoided cost" means the incremental or marginal cost to an electrical utility of electrical energy or capacity, or both, which, but for the purchase of such energy and/or capacity from qualifying facility or qualifying facilities, the utility would generate itself or would purchase from another source.

(b) "Qualifying facility" means any small power production facility or cogeneration facility which is a qualifying facility under federal law.

(c) "Rate" means any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electrical energy or capacity; any rule or practice respecting any such rate, charge, or classification; and any contract pertaining to the sale or purchase of electrical energy or capacity.

3902. Avoided Costs.

(a) Each utility shall pay qualifying facilities a rate for energy and capacity purchases based on the utility's avoided costs.

(b) Each electric utility shall file tariffs setting forth standard rates for purchases from qualifying facilities with a design capacity of 100 KW or less.

(c) A utility shall use a bid or an auction or a combination procedure to establish its avoided costs for facilities with a design capacity of greater than 100 KW.

(d) If a utility can demonstrate to the Commission that a qualifying facility should receive a different rate from that established by these rules, the Commission may authorize such. The burden of establishing such different rate shall be on the utility, and the rate shall be based on the utility's system wide costing principles and other appropriate load and cost data.

(e) Nothing in this rule requires a utility to pay more than its avoided costs of energy and capacity, of energy, or of capacity for purchases from qualifying facilities.

3903. Payment of Interconnection Costs.

(a) Each qualifying facility shall pay the cost of interconnecting with an electric utility for purchases and sales of capacity and energy. To the extent that interconnection costs can be determined in advance of interconnection, each electric utility shall establish the cost of interconnection for purchases of energy and capacity. The interconnection costs shall be fair, reasonable, and nondiscriminatory to each qualifying facility.

(b) The utility and qualifying facility may agree to an installment payment arrangement for interconnection costs.

3904. – 3909. [Reserved].

3910. Standards for Operating Reliability and Safety.

Rules 3910 through 3929 establish standards, as authorized by 18 C.F.R. § 292.308, to ensure the safe and reliable interconnected operations of qualifying facilities with utilities regulated by the Commission.

3911. Responsibility of a Utility to Provide Quality Service.

(a) A utility shall provide substantially the same quality of service to its customers and to the qualifying facility after interconnection of the qualifying facility as the utility provided prior to interconnection of the qualifying facility. The interconnection of the qualifying facility to the utility shall not degrade the utility's quality of service to its other customers. The qualifying facility shall pay for the interconnection facilities necessary to preserve the utility's quality of service to its other customers.

(b) At the request of a qualifying facility or a utility prior to interconnection, a utility may evaluate the quality of service to be provided to the qualifying facility. The cost of conducting an evaluation shall be included as an interconnection cost of a qualifying facility. The evaluation may be used for the following purposes:

(I) to estimate the effects of interconnection on the quality of service to be provided; and

(II) to establish the quality of service that a utility shall provide to a qualifying facility after interconnection.

(c) If the qualifying facility desires a superior quality of service to that established by an evaluation performed pursuant to paragraph (b) of this rule, any increased cost shall be an interconnection cost of the qualifying facility.

3912. Submission of Design Information by a Qualifying Facility.

(a) This rule shall apply only to qualifying facilities with nameplate ratings greater than ten MW. For facilities ten MW or less, see rule 3655.

(b) Any person seeking to establish interconnected operations as a qualifying facility shall provide to the utility with which it proposes to interconnect detailed design information of its proposed facilities at least 150 days prior to the proposed interconnection date. At any time after submission of design information, the utility and the qualifying facility may agree to an interconnection date sooner than 150 days. At the time it provides the detailed design information to the utility, the qualifying facility also shall provide the utility with a copy of all available manufacturers' literature for the equipment to be installed, including installation and operating instructions.

(c) The design information submitted by a qualifying facility shall be sufficient to enable a utility to assess the impact of the proposed interconnection on the utility's system, operating plans, and system expansion plans.

(d) Within 25 days after the receipt of design information, or such longer period as agreed by them, a utility shall notify a qualifying facility whether the design information is adequate or whether additional information is required. If additional information is required, the utility shall specify in writing what additional information is needed; and the qualifying facility shall promptly submit the additional information.

3913. Conferences between a Utility and a Qualifying Facility.

(a) This rule shall apply only to qualifying facilities with nameplate ratings greater than ten MW. For facilities ten MW or less, see rule 3655.

(b) No later than 30 days after a qualifying facility has provided design information to a utility, the utility and the qualifying facility shall confer.

(c) At the conference, the utility shall provide the qualifying facility with the names of governmental agencies which have requirements (such as, without limitation, electrical codes, construction codes, sizing criteria, setback distances, physical clearances, protective devices, inspections, and grounding practices) regulating interconnection.

(d) At the conference, the utility shall inform the qualifying facility of these rules and of the system operation requirements and the safety standards and procedures (such as, without limitation, harmonic content for output voltage levels, recommended use of induction generators, line-commutated inverters, and reliable disconnection equipment) required for interconnection.

3914. Establishment of Requirements for a Qualifying Facility.

(a) Within 25 days after submission of complete design information by a qualifying facility, a utility shall:

(I) establish written operations requirements for the qualifying facility so that interconnection with the qualifying facility will not cause abnormal operation of the utility’s protective equipment; and

(II) inform the qualifying facility of the existing phase conductors and utility’s requirements for system electrical phase sequence/rotation available to the qualifying facility and encourage the qualifying facility to use the existing phasing for the proposed interconnection. The utility shall inform the qualifying facility that any phase imbalances may affect the safety of the proposed service or neighboring customer's loads.

(b) In the event that phased loadings of interconnection cause phase imbalances, the cost of equipment to correct the imbalances shall be an interconnection cost of the qualifying facility.

3915. Compliance with Requirements and Rule Standards.

(a) No utility shall interconnect with a qualifying facility until the qualifying facility has established, to the satisfaction of the utility, that it has complied with the utility's requirements for interconnected operations and the standards established in rules 3910 through 3929.

(b) When a qualifying facility determines that it has complied with all of the requirements of a utility and the standards established in these rules for interconnected operations, the qualifying facility shall give written notice of that fact to the utility. Within 25 days after receipt of that notice, the utility and the qualifying facility shall arrange for an onsite inspection of the qualifying facility. The utility shall inspect the facilities related to the qualifying facility's interconnection with the utility. The qualifying facility shall provide the personnel necessary to operate the facility in order to demonstrate to the utility the proper operation of the qualifying facility's equipment.

(I) If the utility determines from the inspection that the qualifying facility has complied with all of the requirements of the utility and the standards established in these rules, the utility shall certify in writing that the qualifying facility complies.

(II) If the utility determines that the qualifying facility has failed to comply with any requirement of the utility or any standard established in these rules, the utility shall notify the qualifying facility in writing of the requirements or standards that the qualifying facility must meet for interconnection. Upon compliance, the qualifying facility shall give written notice to the utility; and the parties shall proceed as provided in paragraph (b) of this rule.

(c) When the qualifying facility has obtained compliance certification, the qualifying facility and the utility shall schedule a date for the initial energizing and start-up testing of the qualifying facility's generating equipment. The utility at its option may be present at this test.

(I) At the conclusion of the test, the utility shall certify in writing whether the qualifying facility may commence interconnected operations.

(II) If the qualifying facility fails the start-up test, the utility shall so notify the qualifying facility in writing and within five business days. When the qualifying facility has corrected the deficiencies, the parties shall schedule a new start-up test; and the parties shall proceed as provided in paragraph (c) of this rule.

(d) In the event of a disagreement between a qualifying facility and a utility regarding compliance by the qualifying facility with the utility's requirements or with the standards established in these rules or the qualifying facility's failure of the start-up test, either party may file with the Commission a petition for a declaratory order under paragraph 1304(j) seeking resolution of the disagreement.

(e) In the event that either party files a petition for a declaratory order, the Commission shall enter an order resolving the dispute. The qualifying facility or the utility shall comply with the Commission's order prior to interconnection.

3916. Code Certification by a Qualifying Facility.

(a) A qualifying facility shall provide a utility with certification that it has complied with all applicable governmental codes (such as, without limitation, National Electric Safety Code, National Electrical Code as currently adopted by the State Electrical Board, and construction codes as currently adopted by local jurisdictional government).

(b) A qualifying facility shall obtain all necessary certifications at its own cost.

3917. Utility Access to Premises of a Qualifying Facility.

(a) A utility shall have access to a qualifying facility prior to construction to determine if minimum setback distances and physical clearances will be met for the safety of the utility's equipment. The cost of said inspection shall be included as an interconnection cost of the qualifying facility.

(b) A utility shall have access to a qualifying facility to repair, to maintain, or to retrieve any of the utility's equipment affected by a failure of the utility's or qualifying facility's equipment.

(c) A utility shall have access to a qualifying facility to conduct an inspection for the purpose stated in paragraph 3921(d).

(d) A utility shall have access to a qualifying facility to conduct an inspection pursuant to the procedures established pursuant to paragraph 3927(b).

(e) A utility shall have access to a qualifying facility to conduct an inspection pursuant to paragraph 3927(d).

(f) A utility shall have access to a qualifying facility to conduct an inspection pursuant to paragraph 3927(e).

3918. Coordination of Circuit Protection Equipment.

(a) Prior to interconnection and at the earliest time possible after a qualifying facility provides its complete design information, but in no event later than 25 days after submission of complete design information, a utility shall provide a written statement to the qualifying facility as to whether the utility's circuit protection equipment can accommodate the equipment of the qualifying facility.

(b) A utility shall evaluate the effects of a proposed interconnection, together with the aggregate effects of all other interconnections, on the utility's installed circuit protection equipment. Costs of the evaluation shall be an interconnection cost paid by the qualifying facility.

(c) As part of normal planning, a utility shall evaluate the interaction between a qualifying facility's operations and the utility's installed circuit protection equipment. The cost of evaluation shall be an interconnection cost of the qualifying facility.

(d) If the design of a qualifying facility causes replacement or significant re-coordination of the utility's circuit protection equipment, or if the design reasonably can be expected to require extraordinary operation of the utility's installed protection equipment, the utility shall not interconnect with the qualifying facility. The utility shall decline to interconnect until either the design has been modified to eliminate the problems or specific modified designs for the interconnection are established. Replacement and re-coordination costs shall be an interconnection cost of the qualifying facility.

(e) A qualifying facility shall provide the utility with a description of the qualifying facility's electrical and mechanical equipment sufficient for the utility to determine the safety and adequacy of its installed service drops and supply equipment. The qualifying facility shall provide this information at the time it submits its design information to the utility.

3919. Installation of Protective Equipment by a Qualifying Facility to Accommodate Protection Equipment of a Utility.

(a) Within 25 days after a qualifying facility submits its complete design information, a utility shall notify the qualifying facility of any necessity to install protective equipment to accommodate the utility's system protection equipment.

(b) Such notification shall be made in writing and shall list the specific types of protective equipment required and the operations of the utility which necessitate protection.

(c) The qualifying facility shall be responsible for installing protective equipment to accommodate the utility's system protection equipment. The cost of this installation shall be an interconnection cost of the qualifying facility.

(d) A utility shall not be responsible for the effects on a qualifying facility's equipment and systems that are caused by the utility's system or equipment.

3920. Grounding Qualifying Facility Equipment.

(a) A utility shall establish grounding practices that are commensurate with those in the area, taking into consideration soil conditions, the nature of other loads in the area, and the utility's experience. Grounding practices shall be consistent with applicable national, state, and local codes.

(b) A qualifying facility shall ground all equipment to meet governmental codes and the utility's requirements.

(c) A utility shall advise, in writing, a qualifying facility of its grounding requirements within 25 days after the qualifying facility submits its complete design information.

(d) If the grounding of a qualifying facility's equipment degrades safety, necessitating improvements or modifications of the interconnection, the utility shall have the right to approve the improvements or modifications made to the interconnection to assure that they are sufficient to address the safety issue caused by the degradation. The qualifying facility shall bear the responsibility for and the cost of such improvements or modifications.

(e) In the event that grounding of a qualifying facility causes electro-magnetic interference with telephone service, radio or television reception, or the operation of other electrical devices, the qualifying facility shall make the necessary grounding modifications to remove such interference. The cost of such modifications shall be an interconnection cost of the qualifying facility.

(f) No qualifying facility shall commence interconnected operations until it obtains written certification that it has complied with all applicable governmental codes and until the utility approves the grounding of the qualifying facility's equipment.

3921. Standards for Harmonics and Frequency.

(a) A utility shall establish non-discriminatory standards for the harmonic content of power and energy generated by qualifying facilities.

(b) No qualifying facility shall commence interconnected operations until it establishes, to the satisfaction of the utility, that it will produce power and energy at a fundamental frequency of 60 HZ and that such power will not exceed the utility's established standards for harmonic content.

(c) A utility shall not be responsible for onsite interference caused by harmonics, failure of motors, interference with telephone service or television or radio reception, and other manifestations of degraded quality of service which are caused by the failure of a qualifying facility to produce power and energy at 60 HZ.

(d) A qualifying facility shall not operate its generators in such a fashion as to impact negatively the utility's or the utility's customers' voltage range or other voltage characteristics. The qualifying facility shall have adequate voltage regulation and related protective and control equipment as required by the utility.

(e) A qualifying facility shall operate within the utility's power factor and voltage characteristic requirements.

3922. Interconnection at Different Voltage Levels.

(a) A qualifying facility shall interconnect with a utility at the utility's established voltage level.

(b) An interconnection at a voltage level that requires the utility to install different or additional protective equipment, or that requires the utility to make other modifications of its system, shall be an interconnection cost of the qualifying facility.

3923. Types of Generators and Inverting Equipment.

(a) A utility shall establish standards to encourage qualifying facilities to use generators that minimize the safety hazard associated with the possibility of reverse power flow during periods of line outages.

(b) A utility shall adopt power factor standards at the point of interconnection. Such standards shall recognize that a qualifying facility may not produce excessive reactive power during off-peak conditions and may not consume excessive reactive power during on-peak conditions. The qualifying facility shall be responsible for installing, at its expense, the equipment necessary to maintain power factor requirements.

(c) If a qualifying facility's abnormal power factor causes deleterious effects on a utility's system,, unless otherwise provided by contract, the utility shall correct the deleterious effects on its system at the expense of the qualifying facility. Deleterious effects on a qualifying facility's system caused by its abnormal power factor shall be corrected by the qualifying facility at its own expense.

3924. System Protection Equipment.

(a) Prior to interconnection, a qualifying facility shall install protective equipment that will automatically disconnect its generating equipment from a utility's power lines in the event of failure of the qualifying facility's generating equipment, a power line outage, or a nearby system fault.

(I) The protective equipment, or separate equipment, shall have the ability to isolate the energy generated or supplied by a utility or by a qualifying facility. The equipment shall be accessible to and by the utility and the qualifying facility.

(II) A utility shall have the right to operate the protective equipment whenever, in its judgment, it is necessary to maintain safe operating conditions or whenever the operations of a qualifying facility adversely affect the utility's system.

(III) A qualifying facility shall have the right to operate the protective equipment whenever, in its judgment, it is necessary to maintain safe operating conditions or whenever the operations of a utility adversely affect the qualifying facility's equipment.

(IV) Protective equipment that isolates a qualifying facility's generation shall be lockable by a utility only in the open position. Equipment that isolates a utility's generation or supply shall be lockable by a qualifying facility only in the open position. This equipment shall be installed so that there can be visual verification that the equipment is locked in the open position.

(b) Prior to interconnection, a utility shall require a qualifying facility to demonstrate the proper functioning and operation of its protective equipment to the satisfaction of the utility.

(c) A qualifying facility shall install overcurrent protection between major components of all switched interconnections.

(d) A qualifying facility shall install protective relaying equipment to confine the effects of faults, lightning strikes, or other abnormalities and to protect its and a utility's equipment.

(e) Prior to making significant modifications to its equipment, a qualifying facility shall notify a utility with which the QF is interconnected of the proposed modifications. If a qualifying facility plans to make significant modifications to its equipment, or if future difficulties arise on the systems of the qualifying facility or the utility as a result of the interconnection, the utility may require different or additional protective equipment or may require modifications as a condition of continued interconnected operations. The cost of such protective equipment or modifications shall be a cost of the qualifying facility.

(f) No specific number of system protective devices is required by this rule.

3925. Meters.

(a) A utility shall own, install, and maintain meters and associated metering equipment to measure the generation of a qualifying facility.

(b) A qualifying facility shall supply, at no expense to the utility, a suitable location for the installation of metering equipment.

(c) The cost of meters and associated metering equipment, their installation, and their maintenance shall be an interconnection cost of the qualifying facility.

3926. Maintenance and Inspection of a Qualifying Facility.

(a) Prior to interconnection, a qualifying facility shall establish a planned maintenance schedule containing dates, times, and procedures. No qualifying facility shall commence interconnected operations until the utility approves the proposed maintenance schedule. The utility shall not withhold approval unreasonably.

(b) A utility shall establish written procedures for inspecting a qualifying facility and shall provide a copy of the procedures to the qualifying facility prior to interconnection. Inspection procedures may be modified on a case-by-case basis.

(c) A qualifying facility shall keep records of maintenance, and a utility shall keep records of inspections. Each shall have access to the records of the other.

(d) A utility may inspect a qualifying facility, on demand, to determine if the qualifying facility is complying with the previously-approved maintenance schedule and is safely operating all protective equipment.

(e) A utility may inspect the qualifying facility and its records, on demand, to determine if the qualifying facility is, or has been, reselling the utility's energy and/or capacity to the utility.

(f) Personnel from both a utility and a qualifying facility shall have the right to witness inspections. For inspections to determine safety or the reselling of the utility's energy or capacity to the utility, the utility shall inform the qualifying facility that it intends to inspect the facility. If the qualifying facility declines, the inspection shall be conducted without the presence of qualifying facility personnel. If the qualifying facility fails the inspection, the utility shall have the right to disconnect the qualifying facility from the utility’s system until the qualifying facility can demonstrate the proper functioning of the qualifying facility’s protection and control equipment to the satisfaction of utility representatives.

3927. Disconnection of a Qualifying Facility.

(a) If a utility determines that a qualifying facility has not complied with its maintenance schedule, that a qualifying facility's protective equipment is not operating properly, or that a qualifying facility has been reselling the utility's energy or capacity to the utility, the utility may disconnect the qualifying facility without notice or may give the qualifying facility up to 30-days' notice of disconnection.

(b) A notice of disconnection shall inform the qualifying facility of the maintenance to be performed, the operational practices to be modified or terminated, or the repairs to be made to protective equipment to prevent disconnection. To avoid disconnection, the qualifying facility shall comply with all requirements prior to the date of the proposed disconnection. The qualifying facility shall notify the utility when it has complied, at which time the utility shall re-inspect the qualifying facility. If the utility determines that the qualifying facility has complied, the qualifying facility shall not be disconnected. If the utility determines that the qualifying facility has not complied, the qualifying facility shall be disconnected as provided in the notice of disconnection.

(c) A utility and a qualifying facility may agree to a reasonable continuance of a disconnection, or to a reconnection where the qualifying facility has been disconnected, if the utility believes that the qualifying facility is making a bona fide effort to comply. If the qualifying facility has been disconnected for reselling the utility's energy and/or capacity to the utility, the agreement shall be conditioned on the qualifying facility's paying the utility for the resold energy and/or capacity.

3928. Qualifying Facility to File Generation Schedule.

A qualifying facility shall provide a utility with a proposed schedule of generation prior to interconnection. The schedule may be used by the utility to coordinate normal maintenance of its distribution facilities, to coordinate its bulk power supplies, or to coordinate regular operations for the safety of maintenance personnel.

3929. – 3949. [Reserved].

3950. Indemnification and Insurance.

(a) A utility shall indemnify a qualifying facility against all loss, damage, expense, and liability to third persons for injury or death caused by the utility's ownership, construction, operation, maintenance, or failure of its facilities used in the interconnected operations. The utility, at the request of the qualifying facility, shall defend any suit asserting a claim covered by its indemnification. The utility shall pay all costs incurred by the qualifying facility to enforce this indemnification.

(b) A qualifying facility shall indemnify a utility against all loss, damage, expense, and liability to third persons for injury or death caused by the qualifying facility's ownership, construction, maintenance, or failure of its facilities used in the interconnected operations. The qualifying facility, at the request of the utility, shall defend any suit asserting a claim covered by its indemnification. The qualifying facility shall pay all costs incurred by the utility to enforce this indemnification.

(c) Absent a written agreement to the contrary, a utility and a qualifying facility shall hold each other harmless from liability for all damages caused to the facilities of the other party by reason of the improper or otherwise out of compliance operation of, or non-operation of, their facilities.

(d) A qualifying facility shall obtain liability insurance in an amount the utility determines to be reasonably adequate to protect the public and the utility against damages caused by the interconnected operations. Prior to interconnection, the qualifying facility shall provide the utility with a current, valid certificate of insurance naming the utility as a beneficiary. A utility may waive the right to be named as an additional insured.

3951. Discontinuance of Sales or Purchases During System Emergencies, and Notice.

(a) A qualifying facility shall provide energy or capacity to a utility during a system emergency on the utility's system to the extent required by 18 C.F.R. § 292.307.

(b) Unless waived by the utility, a qualifying facility which discontinues sales to or purchases from a utility due to a system emergency:

(I) shall make a reasonable effort to notify the utility by telephone prior to discontinuance. If the qualifying facility is unable to give prior telephone notice to the utility, the qualifying facility shall notify the utility by telephone no later than two hours after the termination of the emergency. No utility shall be entitled to telephone notification under this rule unless it provides its current telephone number to the qualifying facility; and

(II) shall give written notice to the utility no later than five days after the termination of the emergency causing the discontinuance. The written notice shall describe the emergency, the duration of the emergency, and the reasons for the discontinuance.

(c) During a system emergency, a utility may discontinue purchases from a qualifying facility as provided in 18 C.F.R. § 292.307. Unless waived by the qualifying facility, a utility which discontinues purchases from or sales to a qualifying facility due to a system emergency shall give written notice to the qualifying facility no later than ten days after termination of the emergency causing the discontinuance. The written notice shall describe the emergency, the duration of the system emergency, and the reasons for the discontinuance.

(d) As used in this rule, “system emergency” means a condition on a utility’s system that is likely to result in imminent and significant disruption of service to customers or that is likely imminently to endanger life or property.

3952. Other Discontinuances.

Within ten days prior to any type of temporary discontinuance of purchases or sales other than one due to a system emergency, the utility or the qualifying facility shall notify the other party, except that this notification shall not be required if the parties previously have agreed upon the discontinuance or if the discontinuance is less than 15 minutes in duration.

3953. Exemption of Qualifying Facilities from Certain Colorado Laws and Regulations.

(a) A qualifying facility shall be exempt from Colorado law and regulations as provided in 18 C.F.R. § 292.602(c), except that a qualifying facility shall not be exempt from rules 3900 through 3954.

(b) The exemption provided for in 18 C.F.R. § 292.602(c) shall not divest the Commission of the authority to review contracts for purchases and sales of power and energy under §§ 201 and 210 of the Public Utility Regulatory Policies Act of 1978.

3954. – 3975. [Reserved].

3976. Regulated Electric Utility Rule Violations, Civil Enforcement, and Civil Penalties.

An admission to or Commission adjudication for liability for an intentional violation of the following may result in the assessment of a civil penalty of up to $2,000.00 per offense. Fines shall accumulate up to, but shall not exceed, the applicable statutory limits set in § 40-7-113.5, C.R.S.

Citation	Description	Maximum Penalty Per Violation
	Articles 1-7 of Title 40, C.R.S.	$2000
	Commission Order	$2000
Rule 3005(a)-(c);(f)	Records and Record Retention	$2000
Rule 3027(a)	Collection and Use of Customer Data	$1000
Rule 3027(b)	Disclosure of Customer Data	$2000
Rule 3027(c)	Tariff	$1000
Rule 3027(d)	Disclosure of Customer Data	$1000
Rule 3028(a)	Customer Notice	$1000
Rule 3029(a),(b)	Consent Form	$1000
Rule 3030(a)	Disclosure of Customer Data	$2000
Rule 3030(b)	Records	$1000
Rule 3031(a)	Disclosure of Customer Data	$2000
Rule 3031(b)	Records	$1000
Rule 3032(a)	Disclosure of Customer Data	$2000
Rule 3032(c) and (d)	Consent and Records	$1000
Rule 3033(a)	Disclosure of Aggregated Data	$2000
Rule 3033(d)	Tariff	$1000
Rule 3100(a)	Obtaining a Certificate of Public Convenience and Necessity for a Franchise	$2000
Rule 3101(a)	Obtaining a Certificate of Public Convenience and Necessity or Letter of Registration to Operate in a Service Territory	$2000
Rule 3102(a)	Obtaining a Certificate of Public Convenience and Necessity for Facilities	$2000
Rule 3103(a),(c),(d)	Amending a Certificate of Public Necessity for Changes in Service Territory or Facilities	$2000
Rule 3108(a),(c)	Keeping a Current Tariff on File with the Commission	$2000
Rule 3109	Filing a New or Changed Tariff with the Commission	$2000
Rule 3110(b),(c)	Filing an Advice Letter to Implement a Tariff Change	$2000
Rule 3200(a),(b)	Construction, Installation, Maintenance and Operation of Facilities in Compliance with Accepted Engineering and Industry Standards	$2000
Rule 3204	Reporting Incidents Resulting in Death, Serious Injury, or Significant Property Damage	$2000
Rule 3210	Line Extensions	$2000
Rule 3251	Reporting Major Events	$2000
Rule 3252	Filing a Report on a Major Event with the Commission	$2000
Rule 3303(a)-(j)	Meter Testing	$2000
Rule 3306	Record Retention of Tests and Meters	$2000
Rule 3309	Provision of Written Documentation of Readings and Identification of When Meters Will be Read	$2000
Rule 3401	Billing Information, Procedures, and Requirements	$2000
Rule 3603	Resource Plan Filing Requirements	$2000
Rule 3654(a),(d)	Renewable Energy Standards	$2000
Rule 3657(a)	QRU Compliance Plans	$2000
Rule 3662	Annual Compliance Reports	$2000
Rule 3803(c)	Master Meter Exemption Requirements	$2000

Citation	Description	Maximum Penalty Per Violation
Rule 3004(b)-(f)	Disputes and Informal Complaints	$1000
Rule 3202(a),(b),(f),(g)	Maintaining a Standard Voltage and Frequency	$1000
Rule 3203(a),(b)	Trouble Report Response, Interruptions and Curtailments of Service	$1000
Rule 3405	Provision of Service, Rate, and Usage Information to Customers	$1000
Rule 3406	Provision of Source Information to Customers	$1000
Rule 3253	Filing a Supplemental Report on a Major Event with the Commission	$1000
Rule 3208(a)-(c)	Poles	$500
Rule 3403(a)-(q);(s)	Applications for Service, Customer Deposits, and Third Party Guarantees	$500
Rule 3658	Standard Rebate Offer	$500
Rule 3006(a),(b),(e)-(m)	Annual Reporting Requirements	$100
Rule 3304	Scheduled Meter Testing	$100
Rule 3305	Meter Testing Upon Request	$100
Rule 3402(a),(c),(d)	Meter and Billing Error Adjustments	$100
Rule 3404(a)-(f)	Availability of Installation Payments to Customers	$100
Rule 3407	Discontinuance of Service	$100
Rule 3408(a)-(g);(i)	Notice of Discontinuation of Service	$100
Rule 3409	Restoration of Service	$100
Rule 3411(c)(IV),(d)(I),(d)(II),(e)	Low-Income Energy Assistance Act	$100
Rule 3618	Filing of Electric Resource Planning Reports	$100

3977. – 3999. [Reserved].

GLOSSARY OF ACRONYMS

CAAM – Cost Allocation and Assignment Manual
CCR – Colorado Code of Regulations
C.F.R. – Code of Federal Regulations
CPCN - Certificate of Public Convenience and Necessity
CRCP – Colorado Rules of Civil Procedure
C.R.S. - Colorado Revised Statutes
EAO – Energy Assistance Organization
e-mail - Electronic mail
FERC – Federal Energy Regulatory Commission
FDC - Fully Distributed Cost
GAAP - Generally Accepted Accounting Principles
HZ – Hertz (cycles per second)
IEEE – the Institute of Electrical and Electronics Engineers
IPP – Independent Power Producer
KW – KiloWatt (1 KW = 1,000 Watts)
kWh – Kilowatt-hour
MMO – Master Meter Operator
MW – MegaWatt (1 MW = 1,000 KiloWatts)
MWH – MegaWatt-hour
OCC – Colorado Office of Consumer Counsel
RES – Renewable Energy Standard
RUS – Rural Utilities Service of the United States Department of Agriculture
USOA – Uniform System of Accounts

Editor's Notes

History

Entire rule eff. 08/01/2007.

Rules 3000, 3650-3664 eff. 09/30/2007.

Rules 3600-3615 emer. rules eff. 09/28/2007.

Rules 3600-3615 eff. 03/01/2008.

Rule 3975 eff. 03/05/2009.

Rules 3652, 3655, 3658, 3664 emer. rules eff. 09/01/2009; expired 03/24/2010.

Rule 3975 emer. rule eff. 09/23/2009; expired eff. 04/21/2010.

Rules SB&P, 3000, 3650-3699 eff. 03/30/2010.

Rules SB&P, 3009, 3010, 3102, 3206, 3976 eff. 09/14/2010.

Rules SB&P, 3000, 3006, 3600-3618, 3650-3664, 3665.(e)(IX), 3666 eff. 12/30/2010.

Rules 3206.(h), 3625-3627 eff. 06/14/2011.

Rules SB&P, 3000.(c), 3002.(a), 3006, 3600-3605, 3609, 3613-3619 eff. 10/30/2011.

Rules SB&P, 3006.(f)-(n), 3400, 3412 eff. 12/15/2011.

Rules SB&P, 3000.(a)-(b), 3602.(q), 3604.(k)-(l), 3650-3699 eff. 01/14/2012.

Rules 3001, 3011-3099, 3976 eff. 02/14/2012.

Rules 3400, 3413 eff. 02/14/2014.

Rules SB&P, 3000.(c)(XII)-(XIII), 3000.(d)(I), 3650.(e)-(f), 3651, 3652.(c)-(ll), 3654.(b)-(r), 3655.(e), 3655.(h)-(j), 3658.(e), 3659.(a)-(c), 3661.(b), 3662, 3666.(a), 3668.(d), 3976 eff. 06/14/2014.

Rules 3001, 3024-3036, 3976 eff. 09/30/2015.

Rules 3102.(e)-(f), 3205.(a)-(b) eff. 04/14/2016.

Rules 3000-3008, 3010, 3100-3101, 3103-3110, 3202-3204, 3206-3207, 3210, 3250-3253, 3300, 3302-3305, 3309, 3401-3405, 3407-3413, 3501-3503, 3602-3604, 3607-3618, 3627, 3651-3668, 3702-3703, 3803-3804, 3900, 3902, 3911, 3914-3917, 3950-3953, 3976, GLOSSARY OF ACRONYMS eff. 05/15/2016.

Rule 3412 eff. 01/30/2017.

Rule 3627.(c)(IX) eff. 12/15/2017.

Rules SB&P, 3001.(l)-(pp), 3206.(d)(1)(D)-(G), 3207, 3602, 3604.(j)-(k)(m)-(n), 3607, 3608.(c), 3610.(b)(III), 3611.(d)(g), 3613.(d), 3614, 3615.(b), 3616.(a)-(b), 3617.(c) eff. 03/02/2019.

Rule 3008.(g) eff. 04/30/2019.

Rule 3902.(c) eff. 05/30/2019.

Rule 3412.(c) emer. rule eff. 10/18/2019.

Rule 3412.(c) eff. 05/15/2020.

Rules 3600, 3605 eff. 07/15/2020.