COLORADO DEPARTMENT OF REGULATORY AGENCIES
Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

3000. Scope and Applicability.

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[indicates omission of unaffected rules]

(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.

(XIV) Rules 3750 through 3756 concerning regional electricity market participation.

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[indicates omission of unaffected rules]

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) waiver or delay to join a regional market, as provided in rule 3753~~.~~; or

(XX) 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 types of submittal.

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[indicates omission of unaffected rules]

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~~3749. [Reserved].

REGIONAL ELECTRICITY MARKET PARTICIPATION

3750. Scope and Applicability.

Rules 3750 through 3757 shall apply to all jurisdictional electric utilities in the state of Colorado that own and operate transmission facilities and that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity, including rural electric associations, and municipally owned electric utilities are exempt from these rules. Cooperative electric generation and transmission associations are not subject to the requirements in rules 3756 and 3757 but are subject to all other rules governing regional electricity market participation.

3751. Overview and Purpose.

The purpose of these rules is to establish the requirements for transmission utility filings addressing entry into regional electricity markets, reporting requirements for market progress and participation, and applications for the sharing of market participation benefits in accordance with § 40-5-108, C.R.S. In order to promote these purposes, these rules specify the information that transmission utilities must provide to the Commission in these filings and the Commission findings that these filings must support.

3752. Definitions.

(a) "Day Ahead Market" or "DAM" means a market that enables day-ahead unit commitment and dispatch across the participating footprint but does not encompass transfer of operational control of transmission assets.

(b) Energy Imbalance Markets (EIM) means a market that optimizes real-time unit dispatch across the participating footprint but does not enable day-ahead unit commitment.

(c) "Generator Interconnection Procedures and Agreements" means the processes and other approaches through which a Transmission Utility in Colorado enables new generation to interconnect with either its existing or expanded transmission system under FERC rules governing Large Generator Interconnection Procedures (LGIPs) and Agreements (LGIAs).

(d) "Greenhouse Gas Emissions (GHG)" means the anthropogenic emissions included in the definition of Statewide Greenhouse Gas Pollution in CRS Section 25-7-103 (22.5).

(e) "GHG Tracking and Accounting Mechanism" is a set of market and other protocols included in a Regional Market tariff and other related materials that enables the tracking, accounting, and reporting of GHGs.

(f) "Investor-Owned Transmission Utility" or "IOU" means a transmission utility subject to electric rate regulation by the Commission.

(g) "Market operations" means utility participation in any service offered by a regional market.

(h) "OATT" means a utility Open Access Transmission Tariff.

(i) "Pancaking of transmission rates" means the stacking or accumulation of transmission charges for service that uses the transmission facilities of multiple transmission providers.

(j) "Regional market" means any organization that coordinates and enhances wholesale electricity transactions as compared to the bilateral market structure that has historically existed in Colorado but specifically excludes Energy Imbalance Markets.

(k) "Regional Transmission Organization" or "RTO" or "Independent System Operator" or "ISO" means an independent electric transmission operator that provides wholesale transmission services to more than one provider of electric services and generally incorporates centralized real-time dispatch and day ahead unit commitment with a joint transmission tariff. An RTO/ISO also consolidates reliability obligations, transmission planning and cost allocation, and transfers operational control of the transmission system to the system operator.

(l) "Resource adequacy" means the ability of supply-side and demand-side resources to meet the aggregate electrical demand including losses.

(m) "Resource adequacy construct" means a group whose members consist of two or more Balancing Authorities that collectively maintain resource adequacy.

(n) "Statutory Organized Wholesale Market" or "Statutory OWM" means an RTO or ISO that incorporates the characteristics specified in § 40-5-108(1)(a), C.R.S.

(o) "Transmission utility" means a public utility in Colorado that is a wholesale electricity supplier or transmitter and owns and operates electric transmission lines capable of transmitting electric energy at a voltage of one hundred kilovolts or more.

(p) "User" means any entity or affiliate of that entity that buys or sells electric energy in the market's region or in a neighboring region.

3753. Utility Participation in Regional Markets.

(a) The Commission shall determine whether it is in the public interest for a transmission utility to join any regional market.

(I) Early participation in a DAM prior to the June 1, 2028 Market Participation Filing deadline in Section 3753(c) below shall be deemed to be in the public interest if an IOU has complied with the relevant filing requirements in Section 3754 and received a Commission order in accordance with subparagraph 3753(b)(II) and 3753(b)(VI) and a generation and transmission cooperative has received a Commission order in accordance with subparagraph 3753(b)(II).

(II) Participation in a regional market by a generation and transmission cooperative shall be deemed to be in the public interest if the utility has complied with the filing requirements in Section 3754 and received a Commission order either in accordance with subparagraphs 3753(b)(I-III) or paragraph 3753(f).

(III) Participation in a regional market by an IOU shall be deemed to be in the public interest if the utility has complied with the filing requirements in Section 3754 and received a Commission order either in accordance with subparagraphs 3753(b)(I-V) or paragraph 3753(f).

(b) A transmission utility shall have the right to request an order from the Commission finding that the regional market that utility seeks to join:

(I) is a Statutory OWM. The utility's filing shall demonstrate how its participation in the Statutory OWM satisfies the characteristics specified in § 40-5-108(1)(a), C.R.S., and shall include the required contents in each of the paragraphs in rule 3755. If the Commission finds that the market has not satisfied the statutory requirements in § 40-5-108(1)(a), C.R.S., the utility shall file an application for waiver or delay in accordance with rule 3754.

(II) implements a GHG Tracking and Accounting System that enables the fair and timely tracking, reporting, and accounting of GHG emissions sufficient to ensure compliance with the emission reduction requirements in §§ 25-7-102 and 40-2-125.5, C.R.S.

(III) has a FERC-approved Generator Interconnection Procedures and Agreements that enable timely implementation of Colorado's electric resource planning processes and ensure resource adequacy.

(IV) ensures just and reasonable rates for the utility's customers given its approaches to cost allocation, price formation, and market design.

(V) provides a timely path forward for planning, building, and placing in service new transmission.

(VI) has sufficient modelling and other analytical support showing that the expected benefits of joining that market – including dispatch, ancillary services, production cost reductions, and reliability – are likely to exceed the expected costs.

(c) A transmission utility shall seek on order from the Commission pursuant to paragraph 3753(b) or shall file an application for a waiver or delay pursuant to paragraph 3753(f) no later than June 1, 2028, and at least 12 months prior to when the utility commences operations in any regional market.

(d) Upon receipt of a transmission utility's filing pursuant to paragraph 3753(b), the Commission will provide notice to interested persons and specify procedures for the proceeding.

(e) The transmission utility bears the burden of proof and the burden of going forward as the proponent of a decision pursuant to paragraphs 3753(b) or 3754(f).

(f) A transmission utility's application for a waiver or delay of the requirements set forth in § 40-5-108(2)(a)(I), C.R.S., to join a Statutory OWM on or before January 1, 2030, shall state whether the utility requests a waiver or a delay of a specified time period. The application shall set forth good cause for the waiver or delay and shall include:

(I) a description of the utility's efforts to join a Statutory OWM by the January 1, 2030 deadline; and

(II) a description of each regional market in which the utility could reasonably participate, including, if applicable, the market's:

(A) policies regarding tracking and reporting of emissions and assignment of emissions to transmission owners;

(B) policies regarding the promotion of load flexibility and demand-side resource;

(C) policies regarding the promotion of clean energy resources;

(D) policies regarding the reduction of costs and inefficiencies of transactions between balancing areas and between market constructs; and

(E) either an explanation of why the market does not meet the definition of a Statutory OWM pursuant to § 40-5-108(1)(a), C.R.S., or the Commission's order addressing the utility's market assessment of the market.

(III) The results and supporting documentation of any analysis performed by, on the behalf of, or at the request of the transmission utility concerning:

(A) the availability of a Statutory OWM in which the utility could reasonably participate; and

(B) impacts, costs, or benefits of participation in a particular OWM, including costs or benefits to ratepayers and impacts of participation on emissions reduction goals.

3754. Contents of Regional Market Participation Filings.

For all filings made in accordance with paragraphs 3753(b) or (e), the transmission utility shall provide a market overview and shall address the characteristics of the market in paragraphs 3754(b) through 3754(k). The filing shall be organized in a manner that specifically references, and responds to, the requirements contained in each of the following subparagraphs of this rule. To the extent the requested content is not applicable, the utility shall include a statement to that effect and a brief explanation as to why it is not applicable. The transmission utility shall provide workpapers in native format to support the information contained in the filing as appropriate.

(a) Market overview. The transmission utility shall provide:

(I) a description of all market services included in the proposed market;

(II) a map and description of the current scope of the market including a list of participating entities, description of the scope of generation and transmission assets currently participating, and a forecast of anticipated participation in the market;

(III) a description of market processes and accounting including:

(A) terms and conditions for market entry and exit;

(B) generation and transmission bidding procedures and requirements;

(C) provisions and procedures for self-scheduling of resources;

(D) generation unit commitment procedures;

(E) accounting for load served and generation provided; and

(F) other markets processes and requirements as appropriate.

(G) A description of greenhouse gas emission or clean energy policies applicable to both Colorado and non-Colorado market participants.

(b) FERC approval status. The transmission utility shall provide a description of the FERC market approval status and description of any on-going FERC processes or approvals being sought, including, at a minimum:

(I) all relevant FERC proceeding numbers with a description of the approval sought, addressing approval of the market construct; and

(II) all relevant FERC proceeding numbers with a description of the approval sought, addressing approval of the particular utility entry into the proposed market.

(c) Separation of transmission and generation facility control. The transmission utility shall provide a description of the control of transmission facilities as separate from the control of generation facilities, including:

(I) a detailed description of the operational and legal control of transmission facilities. Provide policies and procedures regarding legal and operational control of transmission facilities; and

(II) a detailed description of the operational and legal control of generation facilities.

(d) Transmission rates. The transmission utility shall provide a description of the methodology to establish transmission rates including policies and procedures designed to minimize pancaking of transmission rates in the state of Colorado, including:

(I) the methodology for establishing transmission rates among market and non-market participants including a description of the changes required to the transmission utility OATT; and

(II) a description of how the proposed market policies and procedures minimizes the pancaking of transmission rates.

(e) Reliability and resource adequacy. The transmission utility shall provide an assessment of the impact to long-term and short-term reliability as a result of the proposed market participation, including:

(I) a description of market rules and processes to ensure resource sufficiency and, if applicable, adequacy; and

(II) a description of the interaction between the market processes and procedures regarding resource adequacy and the Commission's resource planning processes.

(f) Net economic benefits. The transmission utility shall provide an assessment of the net economic benefits of the proposed market participation, including:

(I) an analysis of customer benefits and costs of market participation;

(II) forecast of total retail rate impact for 15 years after joining an organized market, including:

(A) forecast of transmission rates and impact on retail and wholesale transmission revenues;

(B) forecast of generation rates and impact on retail and wholesale generation revenues;

(C) a description and forecast of all market participation fees including but not limited to entry fees, exits fees, administrative fees, all capital and operating costs associated with market entry or on-going market participation, etc.; and

(D) forecast of any other relevant costs and benefits.

(g) Market governance. The transmission utility shall provide a description of the governance structure of the proposed market, including:

(I) an overview of governance structure, including:

(A) a description of market committees including committee authorities, committee participation and representation, and meeting standards and practices;

(B) processes and conditions for board selection;

(C) decision making processes;

(D) other governance structures such as working groups and task forces; and

(E) a description of the market monitor including structure, authorities, processes, etc.

(II) a description of how the governance structure and decision-making processes provide state representatives the access and authority necessary to ensure state concerns are substantively addressed. This should include information regarding:

(A) existing or planned states committee's role, authority, funding, and access to the independent board and other decision-making entities;

(B) mechanisms through which the states committee and other state representatives engage in policy issue discussions and initiative prioritization;

(C) a state's role in independent board selection; and

(D) state committee access to market performance data, independent market monitor, market analyses, etc.

(III) a demonstration that the governance or control is independent of the ownership and operation of the transmission facilities.

(IV) a demonstration that no member of the board of directors has an affiliation with a user or with an affiliate of a user during the member's tenure on the board so as to unduly affect the market's performance.

(h) Emission reduction improvements. The transmission utility shall demonstrate that the market improves emission-reduction from operation within the Western Interconnection without significantly impairing actions taken by public utilities to meet the state's emission-reduction goals, including:

(I) a description of the GHG Tracking and Accounting Mechanism for tracking and reporting greenhouse gas emissions across the market region and system for attributing emissions to transmission owners and other load-serving entities;

(II) a forecast of the impact of market participation on greenhouse gas emissions for the next 15 years; and

(III) a description of the GHG Tracking and Accounting Methodology sufficient for this Commission to find that market participation will not negatively impact the goals and implementation of §§ 25-7-102 and 40-2-125.5, C.R.S.

(IV) The transmission utility shall demonstrate that the market includes transmission and generation resources approved, acquired, or constructed and in service by 2030 to meet emission reduction requirements pursuant to §§ 25-7-102 and 40-2-125.5, C.R.S.

(i) Stakeholder process. The transmission utility shall demonstrate that the market has an inclusive and open stakeholder process that does not place unreasonable burdens on, or preclude meaningful participation by, any stakeholder group.

(j) Transmission planning, cost allocation and expansion. The transmission utility shall assess whether the market is consistent with and in support of FERC policies and orders and local planning by Colorado public utilities and Commission rules and shall provide a description of whether the market is capable of:

(I) planning for improved efficiency of use, future expansion, and consideration of all options for meeting transmission needs;

(II) providing effective cost allocations for both existing and new transmission facilities that reflect benefits of transmission investments;

(III) maintaining real-time reliability of the electric transmission system while promoting more efficient use of the transmission system in Colorado and in neighboring areas in the Western Interconnection;

(IV) ensuring comparable and non-discriminatory transmission access and necessary services;

(V) minimizing system congestion; and

(VI) further addressing real or potential transmission constraints.

(k) Interconnection.

(I) The transmission utility shall assess the market's transmission interconnection access, interconnection request processes and queue management, if applicable, including the following information:

(A) a description of the market's current interconnection request process, processes for allocation of interconnection resources, and queue management;

(B) a description of any active or expected initiatives proposing to modify the interconnection access and request process, including information about any application with FERC for approval of modifications;

(C) an explanation of how the current and/or proposed interconnection request process discourages speculative interconnection requests and/or fast-tracks requests for projects approved through utility planning processes;

(D) data characterizing the current interconnection queue status, including at a minimum: MWs of each resource type in each queue stage, average time from interconnection request to signed interconnection agreement, forecast for processing existing queued resources, and any other information necessary to understand how well the queue process is functioning; and

(E) an explanation of how participating in the market will impact current and future requests for interconnection to the utility's transmission system and how this will affect resource planning proceedings.

3755. Reporting Requirements.

(a) Annual progress reporting. Beginning June 1, 2025, each transmission utility shall file with the Commission an annual report describing the current status of its activities related to participating in a regional market. This reporting shall continue annually until the Commission has rendered a decision finding that the transmission utility has joined a Statutory OWM in accordance with subparagraph 3753(a)(V. At a minimum, this report shall include:

(I) identification of any regional market in which the utility is currently a member and the date on which that membership began;

(II) a description of the utility's efforts to join an Statutory OWM or other regional market by the January 1, 2030 deadline, including updates to the activities discussed in the previous report, if applicable; and

(III) in the June 1, 2028 report (if required), an indication of whether at the time of filing the utility intends to file an application for waiver or delay of the requirement to join a Statutory OWM by January 1, 2030.

(b) Informational notice regarding market commitment. Within 30 days of entering a commitment to pursue participation in any regional market or regional resource adequacy construct, the transmission utility shall file with the Commission a notice of this action. The notice shall include a detailed description of the market, the terms of the commitment, the timeline for participation and the expected timeframe for filing an application with the Commission if applicable.

(c) Annual ongoing market participation impact report. Each June 1 that is 12 or more months after the utility commences operations in any regional market, the utility shall file an annual participation impact report for the prior calendar year providing an assessment of the costs, benefits and other consequences of participating in that regional market. At a minimum, this report shall include:

(I) an overview of the regional market including services provided, entities participating, and description of the scope of generation and transmission assets currently participating and forecast to participate in the regional market;

(II) accounting of the costs incurred to join the market and the status of recovering those costs. Include, at a minimum, all administrative, operating, and capital costs associated with market participation;

(III) calculation of the gross and net benefits (or costs) including the benefits sharing to retail ratepayers of the utility's participation in the market, including a breakdown of those benefits by cost category and an explanation of how and when those benefits were realized by ratepayers;

(IV) a detailed assessment of the emissions impact of market participation;

(V) an explanation and assessment of the impacts of market participation on transmission costs paid by retail customers, if applicable; and

(VI) all supporting data, documentation and workpapers related to the analyses in the impact report.

3756. Cost Recovery.

(a) Unless otherwise allowed by a Commission decision, an IOU shall not recover costs associated with its participation in a regional market until the Commission has entered an order determining that the utility's participation in the market is in the public interest or has exempted the IOU from having to file a Market Assessment in the case of a DAM.

(b) Any IOU seeking to recover the costs of regional market participation shall address market terms and conditions including entry and exit fees, market durability, etc. in any application or advice letter seeking recovery of such costs.

(c) In any filing made pursuant to rule 3753 in which the IOU seeks cost recovery, the IOU shall address the anticipated changes to tariffs and any changes to Commission processes needed to implement market participation, including, where applicable:

(I) an estimate of all costs of market implementation and operation including the timing and process for recovery of market-related costs. Provide estimates for all costs, including market entry and exit fees, on-going administrative fees, capital and operation and maintenance costs associated with market participation, etc.;

(II) energy commodity adjustment tariff, rules, accounting and processes;

(III) transmission cost adjustment tariff, rules, accounting and processes;

(IV) recovery of administrative market fees;

(V) modification of market trading rules; and

(VI) any other tariff or process changes needed to implement utility market participation.

3757. Application for Shared Savings from OWM Participation.

(a) Pursuant to § 40-5-108(3), C.R.S., the Commission shall allow an IOU that commences operation with an Statutory OWM, as determined by the Commission in a market assessment, or approved in an application for waiver or delay, to collect and retain a specified percentage of the demonstrated net present value savings accruing to Colorado customers from participation in the Statutory OWM for a maximum period of five years beginning on the date the transmission utility commences operation with the Statutory OWM, however this period shall not extend beyond July 31, 2033. The Commission shall allow an IOU to retain:

(I) up to 35 percent of such savings in years one and two;

(II) up to 25 percent in year three; and

(III) up to 20 percent in years four and five.

(b) An IOU may apply to the Commission to implement a proposed shared savings approach and to establish a proceeding to determine the net present value savings accruing to Colorado customers from the participation of the transmission utility in an Statutory OWM or Alternate OWM.

(c) A utility application requesting to retain a portion of market benefits shall include:

(I) the methodology to determine the net present value savings;

(II) the proposal for sharing mechanism approach; and

(III) the methodology for implementing the sharing mechanism including all necessary tariff changes.

(IV) The utility shall have the burden of proof to demonstrate the net present value of savings.

3758 – 3799. [Reserved].