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§ 34.5 Additional information.

The Commission may, in its discretion, require the filing of additional information which appears necessary to reach a determination on any particular application.

§ 34.6 Form and style.

Each application pursuant to this part 34 shall conform to the requirements of subpart T of part 385 of this chapter.

[Order 182, 46 FR 50514, Oct. 14, 1981, as amended by Order 225, 47 FR 19056, May 3, 1982]

§ 34.7 Filing requirements.

Applications must be filed with the Secretary of the Commission in accordance with filing procedures posted on the Commission's Web site at *http://www.ferc.gov*. If an applicant seeks to protect any portion of an application from public disclosure, the applicant must make its filing in accordance with the Commission's instructions for filing privileged materials and critical energy infrastructure information in this chapter.

[Order 737, 75 FR 43403, July 26, 2010, as amended by Order 769, 77 FR 65474, Oct. 29, 2012]

§ 34.8 Verification.

The original application shall be signed by an authorized representative of the applicant, who has knowledge of the matters set forth therein, and it shall be verified under oath.

EFFECTIVE DATE NOTE: At 70 FR 35375, June 20, 2005, § 34.8 was revised, effective at the time of the next e-filing release during the Commission's next fiscal year. For the convenience of the user, the revised text follows:

§ 34.8 Verification.

An application verification shall be signed under oath by an authorized representative of the applicant, who has knowledge of the matters set forth therein and as provided in § 385.2005 of this chapter, and retained at the applicant's business location until the relevant proceeding has been concluded.

§ 34.9 Reports.

The applicant must file reports under § 131.43 and § 131.50 of this chapter no later than 30 days after the sale or placement of long-term debt or equity securities or the entry into guarantees or assumptions of liabilities pursuant to authority granted under this part.

[Order 575, 60 FR 4853, Jan. 25, 1995. Redesignated by Order 737, 75 FR 43403, July 26, 2010]

EFFECTIVE DATE NOTE: At 70 FR 35375, June 20, 2005, § 34.9 was revised, effective at the time of the next e-filing release during the Commission's next fiscal year. For the convenience of the user, the revised text follows:

§ 34.9 Filing fee.

Each application shall be accompanied by the submission of a filing fee if one is prescribed in part 381 of this chapter.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

Subpart A—Application

Sec.

35.1 Application; obligation to file rate schedules, tariffs and certain service agreements.
35.2 Definitions.
35.3 Notice requirements.
35.4 Permission to become effective is not approval.
35.5 Rejection of material submitted for filing.
35.6 Submission for staff suggestions.
35.7 Electronic filing of tariffs and related materials.
35.8 Protests and interventions by interested parties.
35.9 Requirements for filing rate schedules, tariffs or service agreements.
35.10 Form and style of rate schedules, tariffs and service agreements.
35.10a Forms of service agreements.
35.10b Electric Quarterly Reports.
35.11 Waiver of notice requirement.

Subpart B—Documents To Be Submitted With a Filing

35.12 Filing of initial rate schedules and tariffs.
35.13 Filing of changes in rate schedules, tariffs or service agreements.

Subpart C—Other Filing Requirements

35.14 Fuel cost and purchased economic power adjustment clauses.
35.15 Notices of cancellation or termination.
35.16 Notice of succession.
35.17 Withdrawals and amendments of rate schedule, tariff or service agreement filings.
35.18 Asset retirement obligations.
35.19 Submission of information by reference.

35.19a Refund requirements under suspension orders.
35.21 Applicability to licensees and others subject to section 19 or 20 of the Federal Power Act.
35.22 Limits for percentage adders in rates for transmission services; revision of rate schedules, tariffs or service agreements.
35.23 General provisions.
35.24 Tax normalization for public utilities.
35.25 Construction work in progress.
35.26 Recovery of stranded costs by public utilities and transmitting utilities.
35.27 Authority of State commissions.
35.28 Non-discriminatory open access transmission tariff.
35.29 Treatment of special assessments levied under the Atomic Energy Act of 1954, as amended by Title XI of the Energy Policy Act of 1992.

Subpart D—Procedures and Requirements for Public Utility Sales of Power to Bonneville Power Administration Under Northwest Power Act

35.30 General provisions.
35.31 Commission review.

Subpart E—Regulations Governing Nuclear Plant Decommissioning Trust Funds

35.32 General provisions.
35.33 Specific provisions.

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

35.34 Regional Transmission Organizations.

Subpart G—Transmission Infrastructure Investment Procedures

35.35 Transmission infrasturcture investment.

Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

35.36 Generally.
35.37 Market power analysis required.
35.38 Mitigation.
35.39 Affiliate restrictions.
35.40 Ancillary services.
35.41 Market behavior rules.
35.42 Change in status reporting requirement.
APPENDIX A TO SUBPART H OF PART 35—STANDARD SCREEN FORMAT
APPENDIX B TO SUBPART H OF PART 35—CORPORATE ENTITIES AND ASSETS SAMPLE APPENDIX

Subpart I—Cross-Subsidization Restrictions on Affiliate Transactions

35.43 Generally.
35.44 Protections against affiliate cross-subsidization.

Subpart J—Credit Practices In Organized Wholesale Electric Markets

35.45 Applicability.
35.46 Definitions.
35.47 Tariff provisions governing credit practices in organized wholesale electric markets.

AUTHORITY: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

SOURCE: Order 271, 28 FR 10573, Oct. 2, 1963, unless otherwise noted.

Subpart A—Application

§ 35.1 Application; obligation to file rate schedules, tariffs and certain service agreements.

(a) Every public utility shall file with the Commission and post, in conformity with the requirements of this part, full and complete rate schedules and tariffs and those service agreements not meeting the requirements of § 35.1(g), clearly and specifically setting forth all rates and charges for any transmission or sale of electric energy subject to the jurisdiction of this Commission, the classifications, practices, rules and regulations affecting such rates, charges, classifications, services, rules, regulations or practices, as required by section 205(c) of the Federal Power Act (49 Stat. 851; 16 U.S.C. 824d(c)). Where two or more public utilities are parties to the same rate schedule or tariff, each public utility transmitting or selling electric energy subject to the jurisdiction of this Commission shall post and file such rate schedule, or the rate schedule may be filed by one such public utility and all other parties having an obligation to file may post and file a certificate of concurrence on the form indicated in § 131.52 of this chapter: *Provided, however,* In cases where two or more public utilities are required to file rate schedules or certificates of concurrence such

public utilities may authorize a designated representative to file upon behalf of all parties if upon written request such parties have been granted Commission authorization therefor.

(b) A rate schedule, tariff, or service agreement applicable to a transmission or sale of electric energy, other than that which proposes to supersede, cancel or otherwise change the provisions of a rate schedule, tariff, or service agreement required to be on file with this Commission, shall be filed as an initial rate in accordance with § 35.12.

(c) A rate schedule, tariff, or service agreement applicable to a transmission or sale of electric energy which proposes to supersede, cancel or otherwise change any of the provisions of a rate schedule, tariff, or service agreement required to be on file with this Commission (such as providing for other or additional rates, charges, classifications or services, or rules, regulations, practices or contracts for a particular customer or customers) shall be filed as a change in rate in accordance with § 35.13, except cancellation or termination which shall be filed as a change in accordance with § 35.15.

(d)(1) The provisions of this paragraph (d) shall apply to rate schedules, tariffs or service agreements tendered for filing on or after August 1, 1976, which are applicable to the transmission or sale of firm power for resale to an all-requirements customer, whether tendered pursuant to § 35.12 as an initial rate schedule or tendered pursuant to § 35.13 as a change in an existing rate schedule whose term has expired or whose term is to be extended.

(2) Rate schedules, tariffs or service agreements covered by the terms of paragraph (d)(1) of this section shall contain the following provision when it is the intent of the contracting parties to give the party furnishing service the unrestricted right to file unilateral rate changes under section 205 of the Federal Power Act:

> Nothing contained herein shall be construed as affecting in any way the right of the party furnishing service under this rate schedule to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.

(3) Rate schedules, tariffs or service agreements covered by the terms of paragraph (d)(1) of this section shall contain the following provision when it is the intent of the contracting parties to withhold from the party furnishing service the right to file any unilateral rate changes under section 205 of the Federal Power Act:

> The rates for service specified herein shall remain in effect for the term of _____ or until _____, and shall not be subject to change through application to the Federal Energy Regulatory Commission pursuant to the provisions of Section 205 of the Federal Power Act absent the agreement of all parties thereto.

(4) Rate schedules covered by the terms of paragraph (d)(1) of this section, but which are not covered by paragraphs (d)(2) or (d)(3) of this section, are not required to contain either of the boilerplate provisions set forth in paragraph (d)(2) or (d)(3) of this section.

(e) No public utility shall, directly or indirectly, demand, charge, collect or receive any rate, charge or compensation for or in connection with electric service subject to the jurisdiction of the Commission, or impose any classification, practice, rule, regulation or contract with respect thereto, which is different from that provided in a rate schedule required to be on file with this Commission unless otherwise specifically provided by order of the Commission for good cause shown.

(f) A rate schedule applicable to the sale of electric power by a public utility to the Bonneville Power Administration under section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Pub. L. No. 96–501 (1980)) shall be filed in accordance with subpart D of this part.

(g) For the purposes of paragraph (a) of this section, any service agreement that conforms to the form of service agreement that is part of the public utility's approved tariff pursuant to § 35.10a of this chapter and any market-based rate service agreement pursuant to a tariff shall not be filed with the Commission. All agreements must, however, be retained and be made available for public inspection and copying at the public utility's business office during regular business hours

and provided to the Commission or members of the public upon request. Any individually executed service agreement for transmission, cost-based power sales, or other generally applicable services that deviates in any material respect from the applicable form of service agreement contained in the public utility's tariff and all unexecuted agreements under which service will commence at the request of the customer, are subject to the filing requirements of this part.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 541, 40 FR 56425, Dec. 3, 1975; Order 541–A, 41 FR 27831, July 7, 1976; 46 FR 50520, Oct. 14, 1981; Order 337, 48 FR 46976, Oct. 17, 1983; Order 541, 57 FR 21734, May 22, 1992; Order 2001, 67 FR 31069, May 8, 2002; Order 714, 73 FR 57530, 57533, Oct. 3, 2008; 74 FR 55770, Oct. 29, 2009]

§ 35.2 Definitions.

(a) *Electric service.* The term *electric service* as used herein shall mean the transmission of electric energy in interstate commerce or the sale of electric energy at wholesale for resale in interstate commerce, and may be comprised of various classes of capacity and energy sales and/or transmission services. *Electric service* shall include the utilization of facilities owned or operated by any public utility to effect any of the foregoing sales or services whether by leasing or other arrangements. As defined herein, *electric service* is without regard to the form of payment or compensation for the sales or services rendered whether by purchase and sale, interchange, exchange, wheeling charge, facilities charge, rental or otherwise.

(b) *Rate schedule.* The term *rate schedule* as used herein shall mean a statement of (1) electric service as defined in paragraph (a) of this section, (2) rates and charges for or in connection with that service, and (3) all classifications, practices, rules, or regulations which in any manner affect or relate to the aforementioned service, rates, and charges. This statement shall be in writing and may take the physical form of a contract, purchase or sale or other agreement, lease of facilities, or other writing. Any oral agreement or understanding forming a part of such statement shall be reduced to writing and made a part thereof. A rate schedule is designated with a Rate Schedule number.

(c)(1) *Tariff.* The term *tariff* as used herein shall mean a statement of (1) electric service as defined in paragraph (a) of this section offered on a generally applicable basis, (2) rates and charges for or in connection with that service, and (3) all classifications, practices, rules, or regulations which in any manner affect or relate to the aforementioned service, rates, and charges. This statement shall be in writing. Any oral agreement or understanding forming a part of such statement shall be reduced to writing and made a part thereof. A tariff is designated with a Tariff Volume number.

(2) *Service agreement.* The term *service agreement* as used herein shall mean an agreement that authorizes a customer to take electric service under the terms of a tariff. A service agreement shall be in writing. Any oral agreement or understanding forming a part of such statement shall be reduced to writing and made a part thereof. A service agreement is designated with a Service Agreement number.

(d) *Filing date.* The term *filing date* as used herein shall mean the date on which a rate schedule, tariff or service agreement filing is completed by the receipt in the office of the Secretary of all supporting cost and other data required to be filed in compliance with the requirements of this part, unless such rate schedule is rejected as provided in § 35.5. If the material submitted is found to be incomplete, the Director of the Office of Energy Market Regulation will so notify the filing utility within 60 days of the receipt of the submittal.

(e) *Posting* (1) The term posting as used in this part shall mean:

(i) Keeping a copy of every rate schedule, service agreement, or tariff of a public utility as currently on file, or as tendered for filing, with the Commission open and available during regular business hours for public inspection in a convenient form and place at the public utility's principal and district or division offices in the territory served, and/or accessible in electronic format, and

(ii) Serving each purchaser under a rate schedule, service agreement, or tariff either electronically or by mail in accordance with the service regulations in Part 385 of this chapter with a copy of the rate schedule, service agreement, or tariff. Posting shall include, in the event of the filing of increased rates or charges, serving either electronically or by mail in accordance with the service regulations in Part 385 of this chapter each purchaser under a rate schedule, service agreement or tariff proposed to be changed and to each State Commission within whose jurisdiction such purchaser or purchasers distribute and sell electric energy at retail, a copy of the rate schedule, service agreement or tariff showing such increased rates or charges, comparative billing data as required under this part, and, if requested by a purchaser or State Commission, a copy of the supporting data required to be submitted to this Commission under this part. Upon direction of the Secretary, the public utility shall serve copies of rate schedules, service agreements, or tariffs, and supplementary data, upon designated parties other than those specified herein.

(2) Unless it seeks a waiver of electronic service, each customer, State Commission, or other party entitled to service under this paragraph (e) must notify the public utility of the e-mail address to which service should be directed. A customer, State Commission, or other party may seek a waiver of electronic service by filing a waiver request under Part 390 of this chapter providing good cause for its inability to accept electronic service.

(f) *Effective date.* As used herein the *effective date* of a rate schedule, tariff or service agreement shall mean the date on which a rate schedule filed and posted pursuant to the requirements of this part is permitted by the Commission to become effective as a filed rate schedule. The effective date shall be 60 days after the filing date, or such other date as may be specified by the Commission.

(g) *Frequency regulation.* The term *frequency regulation* as used in this part will mean the capability to inject or withdraw real power by resources capable of responding appropriately to a system operator's automatic generation control signal in order to correct for actual or expected Area Control Error needs.

(16 U.S.C. 284(d), 792 *et seq.;* Pub. L. 95–617; Pub. L. 95–91; E.O. 12009, 42 FR 46267)

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended at 28 FR 11404, Oct. 24, 1963; 43 FR 36437, Aug. 17, 1978; 44 FR 16372, Mar. 19, 1979; 44 FR 20077, Apr. 4, 1979; Order 39, 44 FR 46454, Aug. 8, 1979; Order 699, 72 FR 45325, Aug. 14, 2007; Order 701, 72 FR 61054, Oct. 29, 2007; Order 714, 73 FR 57530, Oct. 3, 2008; Order 755, 76 FR 67285, Oct. 31, 2011]

§ 35.3 Notice requirements.

(a)(1) *Rate schedules or tariffs.* All rate schedules or tariffs or any part thereof shall be tendered for filing with the Commission and posted not less than sixty days nor more than one hundred-twenty days prior to the date on which the electric service is to commence and become effective under an initial rate schedule or tariff or the date on which the filing party proposes to make any change in electric service and/or rate, charge, classification, practice, rule, regulation, or contract effective as a change in rate schedule or tariff, except as provided in paragraph (b) of this section, or unless a different period of time is permitted by the Commission. Nothing herein shall be construed as in any way precluding a public utility from entering into agreements which, under this section, may not be filed at the time of execution thereof by reason of the aforementioned sixty to one hundred-twenty day prior filing requirements. The proposed effective date of any rate schedule or tariff filing having a filing date in accordance with § 35.2(d) may be deferred by the public utility making a filing requesting deferral prior to the rate schedule or tariff's acceptance by the Commission.

(2) *Service agreements.* Service agreements that are required to be filed and posted authorizing a customer to take electric service under the terms of a tariff, or any part thereof, shall be tendered for filing with the Commission and posted not more than 30 days after electric service has commenced or such other date as may be specified by the Commission.

(b) *Construction of facilities.* Rate schedules, tariffs or service agreements predicated on the construction of facilities may be tendered for filing and posted no more than one hundred-twenty days prior to the date set by the parties for the contract to go into effect. The Commission, upon request, may permit a rate schedule or service agreement or part thereof to be tendered for filing and posted more than one hundred-twenty days before it is to become effective.

(16 U.S.C. 284(d); Pub. L. 95–617; Pub. L. 95–91; E.O. 12009, 42 FR 46267)

[44 FR 16372, Mar. 19, 1979; 44 FR 20077, Apr. 4, 1979, as amended by Order 714, 73 FR 57531, Oct. 3, 2008]

§ 35.4 Permission to become effective is not approval.

The fact that the Commission permits a rate schedule or tariff, tariff or service agreement or any part thereof or any notice of cancellation to become effective shall not constitute approval by the Commission of such rate schedule or tariff, tariff or service agreement or part thereof or notice of cancellation.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57531, 57533, Oct. 3, 2008]

§ 35.5 Rejection of material submitted for filing.

(a) The Secretary, pursuant to the Commission's rules of practice and procedure and delegation of Commission authority, shall reject any material submitted for filing with the Commission which patently fails to substantially comply with the applicable requirements set forth in this part, or the Commission's rules of practice and procedure.

(b) A rate filing that fails to comply with this Part may be rejected by the Director of the Office of Energy Market Regulation pursuant to the authority delegated to the Director in § 375.307(a)(1)(ii) of this chapter.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 614, 65 FR 18227, Apr. 7, 2000; Order 699, 72 FR 45325, Aug. 14, 2007; Order 701, 72 FR 61054, Oct. 29, 2007]

§ 35.6 Submission for staff suggestions.

Any public utility may submit a rate schedule, tariff or service agreement or any part thereof or any material relating thereto for the purpose of receiving staff suggestions and comments thereon prior to filing with the Commission.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57531, Oct. 3, 2008]

§ 35.7 Electronic filing of tariffs and related materials.

(a) *General rule.* All filings made in proceedings initiated under this part must be made electronically, including tariffs, rate schedules and service agreements, or parts thereof, and material that relates to or bears upon such documents, such as cancellations, amendments, withdrawals, termination, or adoption of tariffs.

(b) *Requirement for signature.* All filings must be signed in compliance with the following:

(1) The signature on a filing constitutes a certification that: the contents are true and correct to the best knowledge and belief of the signer; and that the signer possesses full power and authority to sign the filing.

(2) A filing must be signed by one of the following:

(i) The person on behalf of whom the filing is made;

(ii) An officer, agent, or employee of the company, governmental authority, agency, or instrumentality on behalf of which the filing is made; or,

(iii) A representative qualified to practice before the Commission under § 385.2101 of this chapter who possesses authority to sign.

(3) All signatures on the filing or any document included in the filing must comply, where applicable, with the requirements in Part 385 of this chapter with respect to sworn declarations or statements and electronic signatures.

(c) *Format requirements for electronic filing.* The requirements and formats for electronic filing are listed in instructions for electronic filing and for each form. These formats are available on the Internet at *http://www.ferc.gov* and can be obtained at the Federal Energy Regulatory Commission, Public Reference Room, 888 First Street, NE., Washington, DC 20426.

(d) Only filings filed and designated as filings with statutory action dates in accordance with these electronic filing requirements and formats will be considered to have statutory action dates. Filings not properly filed and designated as having statutory action dates will not become effective, pursuant to the Federal Power Act, should the Commission not act by the requested action date.

[Order 714, 73 FR 57531, Oct. 3, 2008, as amended by Order 714–A, 79 FR 29076, May 21, 2014]

§ 35.8 Protests and interventions by interested parties.

Unless the notice issued by the Commission provides otherwise, any protest or intervention to a rate filing made pursuant to this part must be filed in accordance with §§ 385.211 and 385.214 of this chapter, on or before 21 days after the subject rate filing. A protest must state the basis for the objection. A protest will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make the protestant a party to the proceeding. A person wishing to become a party to the proceeding must file a motion to intervene.

[Order 612, 64 FR 72537, Dec. 28, 1999; 65 FR 18229, Apr. 7, 2000, as amended by Order 647, 69 FR 32438, June 10, 2004; Order 714, 73 FR 57531, Oct. 3, 2008]

§ 35.9 Requirements for filing rate schedules, tariffs or service agreements.

(a) Rate schedules, tariffs, and service agreements may be filed either by dividing the rate schedule, tariff, or service agreements into individual sheets or sections, or as an entire document except as provided in paragraphs (b) and (c) of this section.

(b) Open Access Transmission Tariffs (OATT) filed by utilities that are not Independent System Operators or Regional Transmission Organizations must be filed either as individual sheets or sections. If filed as sections, the sections must be no larger than the 1.0 level, although each schedule or attachment may be a single section. Individual service agreements that are entered into pursuant to the OATT may be filed as entire documents.

(c) OATT and other open access documents filed by Independent System Operators or Regional Transmission Organizations must be filed either as individual sheets or sections. If filed as sections, the sections must be no larger than the 1.1 level, including schedules or attachments. Individual service agreements that are part entered into pursuant to the OATT may be filed as entire documents.

[Order 714, 73 FR 57531, Oct. 3, 2008]

§ 35.10 Form and style of rate schedules, tariffs and service agreements.

(a) Every rate schedule, tariff or service agreement offered for filing with the Commission under this part, shall show on a title page, which shall be otherwise blank, (1) the name of the filing public utility, (2) the names of other utilities rendering or receiving service under the rate schedule, tariff or service agreement ; and (3) a brief description of the service to be provided under the rate schedule, tariff or service agreement .

(b) At the time a public utility files with the Commission and posts under this part to supersede or change the provisions of a rate schedule, tariff, or service agreement previously filed with the Commission under this part, in addition to the other requirements of this part, it must list in the transmittal letter the sheets or sections revised, and file a marked version of the rate schedule, tariff or service agreement sheets or sections showing additions and deletions. New language must be marked by either highlighting, background shading, bold text, or underlined text. Deleted language must be marked by strike-through.

(c) In any filing to supersede or change the provisions of a rate schedule, tariff, or service agreement previously filed with the Commission under this part, only those revisions appropriately designated and marked under paragraph (b) of this section constitute the filing. Revisions to unmarked portions of the rate schedule, tariff or service agreement are not considered part of the filing nor will any

acceptance of the filing by the Commission constitute acceptance of such unmarked changes.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 568, 59 FR 40240, Aug. 8, 1994; Order 714, 73 FR 57532, Oct. 3, 2008]

§ 35.10a Forms of service agreements.

(a) To the extent a public utility adopts a standard form of service agreement for a service other than market-based power sales, the public utility shall include as part of its applicable tariff(s) an unexecuted standard service agreement approved by the Commission for each category of generally applicable service offered by the public utility under its tariff(s). The standard format for each generally applicable service must reference the service to be rendered and where it is located in its tariff(s). The standard format must provide spaces for insertion of the name of the customer, effective date, expiration date, and term. Spaces may be provided for the insertion of receipt and delivery points, contract quantity, and other specifics of each transaction, as appropriate.

(b) Forms of service agreement submitted under this section shall be filed electronically as prescribed in § 35.7 for the filing of rate schedules.

[Order 2001, 67 FR 31069, May 8, 2002, as amended by Order 714, 73 FR 57532, Oct. 3, 2008]

§ 35.10b Electric Quarterly Reports.

Each public utility as well as each non-public utility with more than a *de minimis* market presence shall file an updated Electric Quarterly Report with the Commission covering all services it provides pursuant to this part, for each of the four calendar quarters of each year, in accordance with the following schedule: for the period from January 1 through March 31, file by April 30; for the period from April 1 through June 30, file by July 31; for the period July 1 through September 30, file by October 31; and for the period October 1 through December 31, file by January 31. Electric Quarterly Reports must be prepared in conformance with the Commission's guidance posted on the FERC Web site (*http://www.ferc.gov*).

(a) For purposes of this section, the term ''non-public utility'' means any market participant that is exempted from the Commission's jurisdiction under 16 U.S.C. 824(f).

The term does not include an entity that engages in purchases or sales of wholesale electric energy or transmission services within the Electric Reliability Council of Texas or any entity that engages solely in sales of wholesale electric energy or transmission services in the states of Alaska or Hawaii.

(b) For purposes of this section, the term ''*de minimis* market presence'' means any non-public utility that makes 4,000,000 megawatt hours or less of annual wholesale sales, based on the average annual sales for resale over the preceding three years as published by the Energy Information Administration's Form 861.

(c) For purposes of this section, the following wholesale sales made by a non-public utility with more than a *de minimis* market presence are excluded from the EQR filing requirement:

(1) Sales by a non-public utility, such as a cooperative or joint action agency, to its members; and

(2) Sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under Federal or state statute.

[Order 768, 77 FR 61924, Oct. 11, 2012, as amended by Order 770, 77 FR 71299, Nov. 30, 2012]

§ 35.11 Waiver of notice requirement.

Upon application and for good cause shown, the Commission may, by order, provide that a rate schedule or tariff, tariff or service agreement, or part thereof, shall be effective as of a date prior to the date of filing or prior to the date the rate schedule or tariff, tariff or service agreement would become effective in accordance with these rules. Application for waiver of the prior notice requirement shall show (a) how and the extent to which the filing public utility and purchaser(s) under such rate schedule or tariff, tariff or service agreement, or part thereof, would be affected if the notice requirement is not waived, and (b) the effects of the waiver, if granted, upon purchasers under other rate

schedules. The filing public utility requesting such waiver of notice shall serve copies of its request therefor upon all purchasers.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57532, 57533, Oct. 3, 2008]

Subpart B—Documents To Be Submitted With a Filing

§ 35.12 Filing of initial rate schedules and tariffs.

(a) The letter of a public utility transmitting to the Commission for filing an initial rate schedule or tariff shall list the documents submitted with the filing; give the date on which the service under that rate schedule or tariff is expected to commence; state the names and addresses of those to whom the rate schedule or tariff has been mailed; contain a brief description of the kinds of services to be furnished at the rates specified therein; and summarize the circumstances which show that all requisite agreement to the rate schedule or tariff or the filing thereof, including any contract embodied therein, has in fact been obtained. In the case of coordination and interchange arrangements in the nature of power pooling transactions, all supporting data required to be submitted in support of a rate schedule or tariff filing shall also be submitted by parties filing certificates of concurrence, or a representative to file supporting data on behalf of all parties may be designated as provided in § 35.1.

(b) In addition, the following material shall be submitted:

(1) Estimates of the transactions and revenues under an initial rate schedule. This shall include estimates, by months and for the year, of the quantities of services to be rendered and of the revenues to be derived therefrom during the 12 months immediately following the month in which those services will commence. Such estimates should be subdivided by classes of service, customers, and delivery points and shall show all billing determinants, e.g., kw, kwh, fuel adjustment, power factor adjustment. These estimates will not be required where they cannot be made with relative accuracy as, for example, in cases of interconnection arrangements containing schedules of rates for emergency energy, spinning reserve or economy energy or in cases of coordination and integration of hydroelectric generating resources whose output cannot be predicted quantitatively due to water conditions.

(2)(i) Basis of the rate or charge proposed in an initial rate schedule or tariff and an explanation of how the proposed rate or charge was derived. For example, is it a standard rate of the filing public utility; is it a special rate arrived at through negotiations and, if so, were unusual customer requirements or competitive factors involved; and is it designed to produce a return substantially equal to the filing public utility's overall rate of return or is it essentially an increment cost plus a share of the savings rate? Were special cost of service studies prepared in connection with the derivation of the rate?

(ii) A summary statement of all cost (whether fully distributed, incremental or other) computations involved in arriving at the derivation of the level of the rate, in sufficient detail to justify the rate, shall be submitted with the filing, except that if the filing includes nothing more than service to one or more added customers under an established rate of the utility for a particular class of service, such summary statement of cost computations is not required. In all cases, the Secretary is authorized to require the submission of the complete cost studies as part of the filing and each filing public utility shall submit the same upon request by the Secretary in such form as he or she shall direct.

(3) A comparison of the proposed initial rate with other rates of the filing public utility for similar wholesale for resale and transmission services.

(4) If any facilities are installed or modified in order to supply the service to be furnished under the proposed rate schedule or tariff, the filing public utility shall show on an appropriate available map (or sketch) and single line diagram the additions or changes to be made.

(5) In support of the design of the proposed rate, the filing public utility shall submit the same material required to be furnished pursuant to

§ 35.13(h)(37) Statement BL. In addition to the summary cost analysis required by Statement BL, the public utility shall also submit a complete explanation as to the method used in arriving at the cost of service allocated to the sales and service for which the rate or charge is proposed, and showing the principal determinants used for allocation purposes. In connection therewith, the following data should be submitted:

(i) In the event the filing public utility considers certain special facilities as being devoted entirely to the service involved, it shall show the cost of service related to such special facilities.

(ii) Computations showing the energy responsibility of the service, based upon considerations of energy sales under the proposed rate schedule or tariff and the kWh delivered from the filing public utility's supply system.

(iii) Computations showing the demand responsibility of the service, and explaining the considerations upon which such responsibility was determined (e.g., coincident or non-coincident peak demands, etc.).

(Federal Power Act, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267; Pub. L. 96–511, 94 Stat. 2812 (44 U.S.C. 3501 *et seq.*))

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended at 28 FR 11404, Oct. 24, 1963; Order 537, 40 FR 48674, Oct. 17, 1975; Order 91, 45 FR 46363, July 10, 1980; Order 714, 73 FR 57532, Oct. 3, 2008]

§ 35.13 Filing of changes in rate schedules, tariffs or service agreements.

CONTENTS

(a) General rule.
(1) Filing for any rate schedule change not otherwise excepted.
(2) Abbreviated filing requirements.
(3) Cost of service data required by letter.
(b) General information.
(c) Information relating to the effect of the rate schedule change.
(d) Cost of service information.
(1) Filing of Period I data.
(2) Filing of Period II data.
(3) Definitions.
(4) Test period.
(5) Work papers.
(6) Additional information.
(7) Attestation.
(e) Testimony and exhibits.
(1) Filing requirements.
(2) Case in chief.
(3) Burden of proof.
(f) Filing by parties concurring in coordination and interchange arrangements.
(g) Commission precedents and policy.
(h) Cost of service statements.
(1) AA—Balance sheets.
(2) AB—Income statements.
(3) AC—Retained earnings statements.
(4) AD—Cost of plant.
(5) AE—Accumulated depreciation and amortization.
(6) AF—Specified deferred credits.
(7) AG—Specified plant accounts (other than plant in service) and deferred debits.
(8) AH—Operation and maintenance expenses.
(9) AI—Wages and salaries.
(10) AJ—Depreciation and amortization expenses.
(11) AK—Taxes other than income taxes.
(12) AL—Working capital.
(13) AM—Construction work in progress.
(14) AN—Notes payable.
(15) AO—Rate for allowance for funds used during construction.
(16) AP—Federal income tax deductions—interest.
(17) AQ—Federal income tax deductions—other than interest.
(18) AR—Federal tax adjustments.
(19) AS—Additional state income tax deductions.
(20) AT—State tax adjustments.
(21) AU—Revenue credits.
(22) AV—Rate of return.
(23) AW—Cost of short-term debt.
(24) AX—Other recent and pending rate changes.
(25) AY—Income and revenue tax rate data.
(26) BA—Wholesale customer rate groups.
(27) BB—Allocation demand and capability data.
(28) BC—Reliability data.
(29) BD—Allocation energy and supporting data.
(30) BE—Specific assignment data.
(31) BF—Exclusive-use commitments of major power supply facilities.
(32) BG—Revenue data to reflect changed rates.
(33) BH—Revenue data to reflect present rates.
(34) BI—Fuel cost adjustment factors.
(35) BJ—Summary data tables.
(36) BK—Electric utility department cost of service, total and as allocated.
(37) BL—Rate design information.
(38) Statement BM—Construction program statement.

(a) *General rule.* Every public utility shall file the information required by this section, as applicable, at the time it files with the Commission under § 35.1 all or part of a rate schedule, tariff or service agreement to supersede or otherwise change the provisions of a

rate schedule, tariff or service agreement filed with the Commission under §35.1. Any petition filed under §385.207 of this chapter for waiver of any provision of this section shall specifically identify the requirement that the applicant wishes the Commission to waive.

(1) *Filing for any rate schedule change or tariff not otherwise excepted.* Except as provided in paragraph (a)(2) of this section, any utility that files a rate schedule, tariff, or service agreement change shall submit with its filing the information specified in paragraphs (b), (c), (d), (e), and (h) of this section, in accordance with paragraph (g) of this section.

(2) *Abbreviated filing requirements*—(i) *For certain small rate increases.* Any utility that files a rate increase for power or transmission services not covered by paragraph (a)(2)(ii) of this section may elect to file under this paragraph instead of paragraph (a)(1) of this section, if the proposed increase for the Test Period, as defined in paragraph (a)(2)(i)(A) of this section, is equal to or less than $200,000, regardless of customer consent, or equal to or less than $1 million if all wholesale customers that belong to the affected rate class consent.

(A) *Definition:* The *Test Period,* for purposes of paragraph (a)(2)(i) of this section, means the most recent calendar year for which actual data are available, the last day of which is no more than fifteen months before the date of tender for filing under §35.1 of the notice of rate schedule.

(B) Any utility that elects to file under this subparagraph must file the following information, conforming its submission to any rule of general applicability and to any Commission order specifically applicable to such utility:

(*1*) A complete cost of service analysis for the Test Period, consistent with the requirements of paragraph (h)(36), Statement BK, of this section.

(*2*) A complete derivation and explanation of all allocation factors and special assignments, consistent with the information required in §35.12(b)(5).

(*3*) A complete calculation of revenues for the Test Period and for the first 12 months after the proposed effective date, consistent with the requirements of paragraph (c)(1) of this section.

(*4*) If the proposed rates contain a fuel cost or purchased economic power adjustment clause, as defined in §35.14, the company must provide the derivation of its base cost of fuel (Fb) and its monthly fuel factors (Fm) for the Test Period and the resulting fuel adjustment clause revenues. If any pro forma adjustments affect the fuel clause in any way, the company must show the impact on Fm, kWh sales in the base period (Sm), Fb and kWh sales in the current period (Sb), as well as on fuel adjustment clause revenues.

(*5*) Rate design calculations and narrative consistent with the information required in paragraph (h)(37) of this section and in §35.12(b)(5).

(*6*) The information required in paragraphs (b), (c)(2) and (c)(3) of this section and in §35.12(b)(2).

(C) Data shall be reconciled with the utility's most recent FERC Form 1. If the utility has not yet submitted Form 1 for the Test Period, the utility shall submit the relevant Form 1 pages in draft form.

(D) The utility may make pro forma adjustments for post-Test Period changes that occur before the proposed effective date and that are known and measurable at the time of filing. The utility shall provide a narrative statement explaining all pro forma adjustments.

(E) If the utility models its filing in whole or in part on retail rate decisions or settlements, the utility must provide detailed calculations and a narrative statement showing how all retail rate treatments are factored into the cost of service.

(F) If the Commission sets the filing for hearing, the Commission will allow the company a specific time period in which to file testimony, exhibits, and supplemental workpapers to complete its case-in-chief. While not required under this subpart, a utility may elect to submit Statements AA through BM for the Test Period in accord with the requirements of paragraphs (d), (g) and (h) of this section.

(ii) *Rate increases for service of short duration or for interchange or coordination service.* Any utility that files a rate

increase for any service of short duration and of a type for which the need and usage cannot be reasonably forecasted (such as emergency or short-term power), or for service that is an integral part of a coordination and interchange arrangement, may submit with its filing only the information required in paragraphs (b), (c) and (h)(37) of this section and in §35.12(b)(2) and (b)(5), conforming its submission to any rule of general applicability and to any Commission order specifically applicable to such utility.

(iii) *For rate schedule, tariff, or service agreement changes other than rate increases.* Any utility that files a rate change that does not provide for a rate increase or that provides for a rate increase that is based solely on a change in delivery points, a change in delivery voltage, or a similar change in service, must submit with its filing only the information required in paragraphs (b) and (c) of this section.

(iv) *Computing rate increases.* For purposes of this subparagraph and paragraph (d)(2)(ii) of this section, the amount of any rate increase shall be the difference between the total revenues to be recovered under the rate change and the total revenues recovered or recoverable under the rate to be superseded or supplemented and shall be determined by:

(A) applying the components of the rate to be superseded or supplemented to the billing determinants for the twelve months of Period I;

(B) Applying the components of the rate change to the billing determinants for the twelve months of Period I; and

(C) Subtracting the total revenues under subclause (A) from the total revenues under subclause (B).

(3) *Cost of service data required by letter.* The Director of the Office of Energy Market Regulation may, by letter, require a utility that is not required under paragraph (a)(1) of this section to submit cost of service data to submit such specified cost of service data as are needed for Commission analysis of the rate schedule change.

(b) *General information.* Any utility subject to paragraph (a) of this section shall file the following general information:

(1) A list of documents submitted with the rate change;

(2) The date on which the utility proposes to make the rate change effective;

(3) The names and addresses of persons to whom a copy of the rate change has been posted;

(4) A brief description of the rate change;

(5) A statement of the reasons for the rate change;

(6) A showing that all requisite agreement to the rate change, or to the filing of the rate change, including any agreement required by contract, has in fact been obtained;

(7) A statement showing any expenses or costs included in the cost of service statements for Period I or Period II, as defined in paragraph (d)(3) of this section, that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices; and

(c) *Information relating to the effect of the rate change.* Any utility subject to paragraph (a) of this section shall also file the following information or materials:

(1) A table or statement comparing sales and services and revenues from sales and services under the rate schedule, tariff, or service agreement to be superseded and under the rate change, by applying the components of each such rate schedule or tariff to the billing determinants for each class of service, for each customer, and for each delivery point or set of delivery points that constitutes a billing unit:

(i) Except as provided in clause (ii), for each of the twelve months immediately before and each of the twelve months immediately after the proposed effective date of the rate change, and the total for each of the two twelve month periods; or

(ii) At the election of the utility:

(A) If the utility files Statements BG and BH under paragraph (h) for Period I, for each of the twelve months of Period I instead of for the twelve months immediately before the proposed effective date of the rate change; and

(B) If Period II is the test period, for each of the twelve months of Period II

instead of for the twelve months immediately after the proposed effective date of the rate change;

(2) A comparison of the rate change and the utility's other rates for similar wholesale for resale and transmission services; and

(3) If any specifically assignable facilities have been or will be installed or modified in order to supply service under the rate change, an appropriate map or sketch and single line diagram showing the additions or changes to be made.

(d) *Cost of service information*—(1) *Filing of Period I data.* Any utility that is required under paragraph (a)(1) of this section to submit cost of service information, or that is subject to the exceptions in paragraphs (a)(2)(i) and (a)(2)(ii) of this section but elects to file such information, shall submit Statements AA through BM under paragraph (h) of this section using:

(i) Unadjusted Period I data; or

(ii) Period I data adjusted to reflect changes that affect revenues and costs prior to the proposed effective date of the rate change and that are known and measurable with reasonable accuracy at the time the rate schedule change is filed, if such utility:

(A) Is not required to and does not file Period II data;

(B) Adjusts all Period I data to reflect such changes; and

(C) Fully supports the adjustments in the appropriate cost of service statements.

(2) *Filing of Period II data.* (i) Except as provided in clause (ii) of this subparagraph, any utility that is required under paragraph (a)(1) of this section to submit cost of service information shall submit Statements AA through BM described in paragraph (h) using estimated costs and revenues for Period II;

(ii) A utility may elect not to file Period II data if:

(A) The utility files a rate increase that is less than one million dollars for Period I; or

(B) All wholesale customers that belong to the affected rate class have consented to the rate increase.

(3) *Definitions.* For purposes of this section:

(i) *Period I* means the most recent twelve consecutive months, or the most recent calendar year, for which actual data are available, the last day of which is no more than fifteen months before the date of tender for filing under § 35.1 of the notice of rate change;

(ii) *Period II* means any period of twelve consecutive months after the end of Period I that begins:

(A) No earlier than nine months before the date on which the rate change is proposed to become effective; and

(B) No later than three months after the date on which the rate change is proposed to become effective.

(4) *Test period.* If Period II data are not submitted for Statements AA through BM, Period I shall be the test period. If Period II data are submitted for Statements AA through BM, Period II shall be the test period.

(5) *Work papers.* A utility that files adjusted Period I data or that files Period II data shall submit all work papers relating to such data. The utility shall provide a comprehensive explanation of the bases for the adjustments or estimates and, if such adjustments or estimates are based on a regularly prepared corporate budget, shall include relevant excerpts from such budget. Work papers and documents containing additional explanatory material shall be provided in electronic format, shall be legible, shall be assigned page numbers, and shall be marked, organized and indexed according to:

(A) Subject matter;

(B) The cost of service statements to which they apply; and

(C) Witness.

(6) *Attestation.* A utility shall include in its filing an attestation by its chief accounting officer or another of its officers that, to the best of that officer's knowledge, information, and belief, the cost of service statements and supporting data submitted under this paragraph are true, accurate, and current representations of the utility's books, budgets, or other corporate documents.

(e) *Testimony and exhibits*—(1) *Filing requirements.* (i) A utility subject to paragraph (a)(1) of this section shall file Statements AA through BM under

paragraph (h) as exhibits with its rate change and may file any other exhibits in support of its rate schedule change.

(ii) A utility subject to paragraph (a)(1) of this section shall file prepared testimony. Such testimony shall include an explanation of all exhibits, including Statements AA through BM, and shall include support for all adjustments to book or budgeted data relied on in preparing the exhibits.

(iii) To the extent that testimony and exhibits other than Statements AA through BM duplicate information required to be submitted in such statements, the testimony and exhibits may incorporate such information by referencing the specific statement containing such material.

(2) *Case in chief.* In order to avoid delay in processing rate filings, such cost of service statements, testimony, and other exhibits described in paragraph (e)(1) of this section shall be the utility's case in chief in the event the matter is set for hearing.

(3) *Burden of proof.* Any utility that files a rate increase shall be prepared to go forward at a hearing on reasonable notice on the data submitted under this section, to sustain the burden of proof under the Federal Power Act of establishing that the rate increase is just and reasonable and not unduly discriminatory or preferential or otherwise unlawful within the meaning of the Act.

(f) *Filing by parties concurring in coordination and interchange arrangements.* For coordination and interchange arrangements in the nature of power pooling transactions, all information required to be submitted in support of a rate change under paragraphs (a)(1), (2), and (3) of this section shall be submitted by each party filing a certificate of concurrence under §35.1. If a representative is designated and authorized in accordance with §35.1 to file supporting information on behalf of all parties to a rate change, such filing shall fulfill the requirement in this paragraph for individual submittals by each party.

(g) *Commission precedents and policy.* If a utility submits cost of service data under paragraph (d) of this section, it shall conform all such submissions to any rule of general applicability and to any Commission order specifically applicable to such utility.

(h) *Cost of service statements.* Any utility subject to paragraph (a)(1) of this section shall submit the following Statements AA through BM in accordance with the requirements of paragraphs (d) and (g) of this section.

(1) *Statement AA—Balance sheets.* Statement AA consists of balance sheets as of the beginning and the end of both Period I and Period II, and the most recently available balance sheet, including any applicable notes, and an explanation of any significant accounting changes since the most recent filing by the utility under this section that involves the same wholesale customer rate class. Balance sheets shall be constructed in accordance with the annual report form for electric utilities specified in part 141.

(2) *Statement AB—Income statements.* Statement AB consists of income statements for both Period I and Period II, and the most recently available income statement, including any applicable notes, and an explanation of any significant accounting changes since the most recent filing by the utility under this section that involves the same wholesale customer rate class. Income statements shall be prepared in accordance with the annual report form for electric utilities specified in part 141.

(3) *Statement AC—Retained earnings statements.* Statement AC consists of retained earnings statements for both Period I and Period II, and the most recently available retained earnings statement, including any notes applicable thereto. Retained earnings statements shall be prepared in accordance with the annual report form for electric utilities specified in part 141.

(4) *Statement AD—Cost of plant.* Statement AD is a statement of the original cost of total electric plant in service according to functional classification for Period I and Period II. If the plant functions and subfunctions for Period I and Period II are different, the utility shall explain and justify the differences.

(i) For each separately identified function and subfunction of production plant or transmission plant, the utility shall state the original cost as of the

beginning of the first month and the end of each month of both Period I and Period II, with an average of the thirteen balances for each period. If any of the Period I or Period II thirteen monthly balances is not available or is unrepresentative of the current plan of the utility for plant in service, the utility shall provide an explanation of the relevant circumstances.

(ii) For each separately identified function and subfunction of plant other than production or transmission, the utility shall state the original cost as of the beginning and the end of both Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I or Period II balances is not available or is unrepresentative of the current plan of the utility for plant in service, the utility shall provide an explanation of the relevant circumstances.

(iii) The utility shall show the electric plant in service in accordance with each of the following five major functional classifications:

(A) Production;

(B) Transmission;

(C) Distribution;

(D) General and Intangible; and

(E) Common and Other.

(iv) To the extent feasible, the utility shall show completed construction not classified in accordance with clause (iii) in accordance with tentative classification to major functional accounts. If this is not feasible, the utility shall describe such facilities as other plant under clause (iii)(E).

(v) If a utility designs its rate change so that subdivision of the major functional classifications is necessary to support the changed rate, the utility shall supply the original cost information for any of the five major functional plant classifications in clause (iii) that are divided into subfunctional categories. If subfunctional original cost information is provided, the utility shall explain the importance of providing such information to support the changed rate. The utility shall describe each subfunctional category in substantive terms, such as *steam electric production* or *high voltage transmission*.

(vi) The utility shall select any subfunctional categories, as appropriate, under the following criteria:

(A) Production plant categories shall be established as necessary to segregate costs for production services with special characteristics, such as base, intermediate or peaking load. The utility shall provide a description of each such service and shall list a brief descriptive title for each corresponding subfunctional category.

(B) Transmission plant categories shall be chosen to reflect the extent to which the facilities are proposed to be allocated on a common basis among all or specific segments of utility services. For descriptive purposes, plant may also be categorized according to accounting or engineering terminology, such as *high voltage overhead lines*. The utility shall provide brief descriptive transmission category titles and explain the basis for the titles. If a utility allocates all transmission plant among utility services on the basis of a single set of allocation data, the utility may show original cost in total without subfunctionalization.

(C) Distribution plant categories shall be selected according to engineering or use characteristics meaningful for allocations or assignments to wholesale services such as substations, overhead lines, meters, or non-wholesale. The utility shall provide brief descriptive distribution category titles and shall explain the basis for the titles.

(D) If the utility divides any general, intangible, common, and other plant functional classifications into subfunctional categories, the subfunctional categories shall be chosen to group together facilities that share a common basis for allocation between wholesale and other electric services. The utility shall provide a brief descriptive title for each general and intangible subfunctional category, and for each common and other subfunctional category, with an explanation of the basis of each category selection. A utility need not divide the functional classifications of plant into subfunctional categories if these functions of plant are allocated in Statement BK on the basis of utility labor expenses.

(E) A separate category shall be provided for each specific assignment of plant reported in Statement BE. Such assignments are applicable principally

but not necessarily exclusively to distribution facilities. The utility shall provide brief descriptive titles consistent with Statement BE.

(F) A separate category shall be provided for each exclusive-use commitment of major power supply facilities as required to be reported at Statement BF. The utility shall provide brief descriptive titles consistent with Statement BF.

(5) *Statement AE—Accumulated depreciation and amortization.* Statement AE is a statement of the accumulated provision for depreciation and amortization of electric plant for Period I and Period II, provided according to major functional classifications selected by the utility in Statement AD under paragraph (h)(4) and divided into the subfunctional categories selected by the utility in Statement AD, to the extent that subfunctionalized data are available.

(i) For each function and subfunction of electric production and transmission plant in service identified in Statement AD, the utility shall set forth the accumulated depreciation and amortization as of the beginning of the first month and the end of each month of both Period I and Period II. The utility shall state an average for each period computed as the average of the thirteen balances.

(ii) For each function and subfunction of electric plant in service other than production or transmission, identified in Statement AD, the utility shall state the accumulated depreciation and amortization as of the beginning and the end of Period I and Period II, with an average of the beginning and end balances for each period.

(iii) If any of the Period I or Period II balances is not available or is unrepresentative of the current plan of the utility for depreciation reserves, the utility shall provide an explanation of the relevant circumstances.

(iv) If accumulated depreciation and amortization data are not available for any subfunction selected in Statement AD, the utility shall:

(A) Provide a comparison of the current depreciation rate of the major functional classification and the depreciation rate estimated to be appropriate to the subfunctional category; and

(B) State and explain the estimation techniques which the utility proposes to utilize in the absence of subfunctional data, such as the proration of accumulated depreciation and amortization data among the subfunctional categories according to the data for electric plant in service in Statement AD. If any of the proposed estimation techniques require data that are not provided elsewhere in the cost of service statements in paragraph (h) of this section, the utility shall supply the necessary data in Statement AE.

(6) *Statement AF—Specified deferred credits.* Statement AF consists of balances of specified accounts and items which are to be considered in the determination of the net original cost rate base. All required balances are to be stated as of the beginning and end of both Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I and Period II balances is not available or is unrepresentative of the current operating plan of the utility, the utility shall include an explanation of the relevant circumstances. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities that have jurisdiction, balances shall be provided in accordance with such subaccounts, with detailed explanations of the bases upon which the subaccounts were established and are maintained. The balances of deferred credits required to be filed in this statement are described in paragraph (h)(6) (i) through (v) of this section. All references to numbered accounts refer to the Commission's Uniform System of Accounts, 18 CFR part 101.

(i) The utility shall state total electric balances for accumulated deferred investment tax credits Account 255, and shall separate the credits into balances applicable to pre-1971 and post-1970 qualifying property additions. If the utility maintains records to show Account 255 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall provide the component balances by function. If the data are not available

by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AF the necessary data, such as historical functional patterns of plant additions eligible for the tax credits. The utility shall state whether the Internal Revenue Code General Rule, §46(f)(1), is applicable with respect to restrictions on credit treatment for ratemaking purposes. If the General Rule is not applicable, the utility shall state which election it has made with respect to special rules for ratable or immediate flow-through for ratemaking purposes.

(ii) The utility shall state the total electric component balances for accumulated deferred income tax Account 281 pertaining to accelerated amortization property. The utility shall show separate components for defense, pollution control, and other facilities. The utility shall show balances for each component and totaled for the electric utility department. If the utility maintains records to show Account 281 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall provide such component balances. If data are not available by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AF the necessary data.

(iii) The utility shall state the total electric component balances for accumulated deferred income tax Account 282 pertaining to electric utility property other than accelerated amortization property. The utility shall itemize the balances in Account 282, to the extent data are available, in detail sufficient to identify the specific major properties involved and shall list the balances according to the accounting entries, such as liberalized depreciation, for which interperiod tax allocation was used and included in this account. Component balances shall be shown individually and in total for the electric utility department. If the utility maintains records to show account 282 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall provide such component balances by function. If the data are not available by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AF the necessary data, such as historical functional patterns of plant additions.

(iv) The utility shall state the total electric component balances for accumulated deferred income tax Account 283 pertaining to interperiod income tax allocations not related to property. The utility shall itemize in detail balances in Account 283, to the extent data are available, and shall list the balances according to the accounting entries for which interperiod tax allocation was used and included in this account. Component balances shall be shown individually and in total for the electric utility department. If the utility maintains records to show Account 283 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall provide such component balances by function. If the data are not available by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The

utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the filing shall supply in Statement AF the necessary data.

(v) The utility shall show electric utility balances for every other item that the utility believes should be included in Statement AF. The utility shall explain the reasons for inclusion of each item.

(7) *Statement AG—Specified plant accounts (other than plant in service) and deferred debits.* Statement AG is a statement of balances of specified accounts and items that are to be considered in the determination of the net original cost rate base. Except as prescribed in clause (ii), the utility shall state all required balances as of the beginning and the end of Period I and Period II, with an average of the beginning and end balances for each period. If any of the Period I or Period II balances is not available or is unrepresentative of the current operating plan of the utility, the utility shall provide a full explanation of the relevant circumstances. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities having jurisdiction, the utility shall provide balances in accordance with such subaccounts, with detailed explanations of the bases upon which the subaccounts were established and are maintained. The balances required to be submitted under Statement AG are described in clauses (7)(i) through (vi).

(i) For each separately identified major functional classification selected by the utility in Statement AD, the utility shall state the electric utility land and land rights balances for electric plant held for future use in account 105. If itemized in detail, balances shall be totaled for each major functional classification.

(ii) The utility shall state the electric utility component balances in Accounts 107 and 120.1, individually and in total, for each item of construction work in progress for pollution control facilities, fuel conversion facilities, or any other facilities that qualify for inclusion in rate base under §35.26. The utility shall state such balances for each major functional and subfunctional classification under Statement AD as of the beginning of the first month and the end of each month of Period I and Period II with an average of the 13 balances for each period.

(iii) For each major functional classification under Statement AD and with respect to property otherwise includable in plant in service, the utility shall state the balances for extraordinary property losses Account 182. If itemized in detail, balances shall be totaled for each major functional classification. The utility shall provide information about Commission authorization for any loss included in Account 182 and shall state when the loss was claimed for tax purposes.

(iv) The utility shall state the total electric component balances for accumulated deferred income taxes Account 190. The component balances in Account 190 shall be itemized in detail and listed according to the accounting entries for which interperiod tax allocation was used. Component balances shall be shown individually and in total for the electric utility department. If the utility maintains records to show Account 190 component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall provide such component balances by function. If the data are not available by function, the filing utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AG the necessary data.

(v) Balances shall be shown for every other item that the utility believes should be included in Statement AG. The utility shall provide support for inclusion of each item, and a brief descriptive title for each such item.

(8) *Statement AH—Operation and maintenance expenses.* Statement AH is a

statement of electric utility operation and maintenance expenses for Period I and Period II provided according to the accounts prescribed by the Commission's Uniform System of Accounts, 18 CFR part 101.

(i) For Period I and Period II, the utility shall itemize and subtotal all operation and maintenance expenses according to the major functional classifications of Statement AD in paragraph (h)(4) and the subfunctional categories of those classifications. The utility shall further divide the operation and maintenance expenses itemized under the production classification and each of its subfunctional categories to reflect expenses relating to the energy component (list each item by account number and compute fuel costs on an as-burned basis), the demand component, and any other production expenses.

(ii) For Period I and Period II, the utility shall report production operation and maintenance expenses according to appropriate account numbers. The utility shall apply the following principles in developing Period I and Period II production operation and maintenance data for this statement:

(A) Total production operation and maintenance expenses shall be segregated into energy, demand, and other components. The utility shall specifically state and support its criteria for classifications between energy and demand, and for use of the production *other* classification, such as specific assignments related to sales from particular generating units.

(B) Fuel expense for cost of service purposes shall be the total as-burned expense incurred. If the utility defers a portion of such expense for accounting purposes, the deferral amount shall be separately stated and accompanied by material that shows computational detail in support of such amount. If claimed nuclear fuel expense reflects a change in the estimated net salvage value of nuclear fuel, the utility shall show the amounts involved and explain the relevant circumstances.

(C) If the amount of production fuel expense is significantly affected by abnormal Period I water availability for hydroelectric generation, the utility shall explain how water availability was taken into account in developing projected Period II production fuel expenses.

(iii) For Period I and Period II, the utility shall report operation and maintenance expenses attributable to the transmission and distribution functions according to appropriate account numbers. If Period II transmission and distribution plant data are not provided by subfunctional category in Statement AD, the utility need only provide for Period II total operation and maintenance expenses for each function.

(iv) For Period I and Period II, the utility shall report in total for each period, operation and maintenance expenses incurred under each of the categories of customer accounting, customer service and information, and sales.

(v) For Period I and Period II, the utility shall itemize administrative and general expenses by groups that are directly assignable, such as regulatory Commission expenses, or that are related to selected plant or expense items for which an allocation to wholesale services is independently determinable, such as items related to labor expense or to a category of production plant in service. Administrative and general expenses shall include a detailed itemization of the general advertising Account 930.1 and the miscellaneous general expenses Account 930.2. If Account 930 data are not projected on a detailed basis for Period II, the utility shall provide its best estimate of the Account 930.1 expense items and a descriptive list of expense items anticipated as miscellaneous general expenses in Account 930.2. Where applicable, separate items shall be shown for general plant maintenance, and for common and other plant maintenance.

(vi) In addition to annual production data for Period I and Period II, the utility shall provide monthly expense data by accounts for fuel in Accounts 501, 518, and 547 and purchased power in Account 555. For each type of transaction, such as firm power or economy interchange power, monthly purchased power expense data shall be subtotaled separately for interchange receipts and deliveries. For monthly fuel Accounts

501, 518, and 547, and for each type of purchased power transaction, the monthly data shall identify components to be claimed under the fuel adjustment clause of the utility.

(9) *Statement AI—Wages and salaries.* Statement AI consists of statements of the electric utility wages and salaries, for Period I and Period II, that are included in operation and maintenance expenses reported in Statement AH.

(i) For Period I and Period II, the utility shall show the distribution of wages and salaries by function according to the form prescribed for operation and maintenance expenses by the Commission's Uniform System of Accounts, 18 CFR part 101. The statement shall also include by function additional wages and salaries attributable to common and other plant classifications identified in Statement AD in paragraph (h)(4).

(ii) For Period I and Period II, the utility shall show total production wages and salaries, itemized and subtotaled into energy and demand related components in accordance with classifications of Statement AH operation and maintenance production expenses of which production wages and salaries are a part.

(10) *Statement AJ—Depreciation and amortization expenses.* Statement AJ consists of statements of depreciation and amortization expenses for Period I and Period II.

(i) For Period I and Period II, the utility shall show the depreciation and amortization expenses and the depreciable plant balances of the filing utility, in accordance with major functional classifications selected by the utility in Statement AD under paragraph (h)(4).

(ii) The utility shall divide the major functional classifications of depreciation and amortization expenses shown in clause (i) into the subfunctional categories selected by the utility for electric plant in service in Statement AD, to the extent such data are available.

(iii) If depreciation and amortization expense data are not available for any subfunctional category selected in Statement AD, the utility shall:

(A) Provide a comparison of the current depreciation rate of the major functional classification and the depreciation rate estimated to be appropriate to the subfunctional category; and

(B) State and explain the estimation techniques that the utility utilized in developing each estimated subfunctional depreciation rate. If utilization of such estimation techniques requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply such data in Statement AJ.

(iv) For Period I and Period II, the utility shall show the annual depreciation rate applicable to each function and subfunction for which depreciation expense is reported. The utility shall indicate the bases upon which the depreciation rates were established. If the depreciation rates used for Period I or Period II data differ from those employed to support the utility's prior approved jurisdictional electric rate, the utility shall include in or append to Statement AJ detailed studies in support of such changes. These detailed studies shall include:

(A) Copies of any reports or analyses prepared by any independent consultant or utility personnel to support the proposed depreciation rates; and

(B) A detailed capital recovery study showing by primary account the depreciation base, accumulated provision for depreciation, cost of removal, net salvage, estimated service life, attained age of survivors, accrual rate, and annual depreciation expense.

(11) *Statement AK—Taxes other than income taxes.* Statement AK consists of statements of taxes other than income taxes for Period I and Period II.

(i) For Period I and Period II, the utility shall itemize and total any taxes other than income taxes according to clauses (i) (A) through (D).

(A) *Revenue taxes.* The utility shall show total revenue taxes levied by each taxing authority and identify the revenue taxes, under both the present and changed rate, applicable to wholesale services for which a rate change is filed. The utility shall identify revenue taxes associated with each revenue credit item reported in Statement AU under paragraph (h)(21).

(B) *Real estate and property taxes.* The utility shall itemize and total all real estate and property taxes. If the utility

maintains records to show tax component balances according to the major functional classifications identified in Statement AD under paragraph (h)(4), the utility shall supply the component balances by function. If the data are not available by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply the necessary data in Statement AK.

(C) *Payroll taxes.* The utility shall itemize and total all payroll taxes. If the utility maintains records to show tax component balances according to the major functional classifications identified in Statement AD in paragraph (h)(4), the utility shall provide the component balances by function. If the data are not available by function, the utility shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall provide the necessary data in Statement AK.

(D) *Miscellaneous taxes.* The utility shall itemize and total all miscellaneous taxes which are directly assignable or which are related to any selected plant or expense item for which an allocation to wholesale services is independently determinable, such as items related to transmission plant in service or to net distribution plant.

(ii) If any of the taxes itemized under clause (11)(i) are levied by a taxing authority that is a customer, or is related to a customer, whose services would be affected by the changed rate schedule, the utility shall show amounts of such taxes according to the taxing authority, identify the related customer, and provide an explanation of the relevant circumstances.

(12) *Statement AL—Working capital.* Statement AL consists of statements for Period I and Period II designed to establish the need for working capital to maintain adequate levels of operating supplies, to meet required prepayments, and to meet ongoing cash disbursements that must be made at a time different than related revenue receipts for utility services rendered.

(i) *Supplies and prepayments.* The utility shall supply statements to show monthly balances of operating supplies and prepayments itemized under clauses (i) (A) through (C). The utility shall state all required balances as of the beginning of the first month and the end of each month of both Period I and Period II, with an average of the thirteen balances for each period. If any of the Period I or Period II balances is not available or is unrepresentative of the current operating plan of the utility for supplies or prepayments, the utility shall include an explanation of the relevant circumstances. Operating supply and prepayment balances shall be itemized under the following categories:

(A) *Fuel supplies.* The utility shall state the fuel supply balances for each type of electric utility production plant, except hydraulic. The utility shall describe its overall fossil fuel supply objectives for Period I and Period II, in terms of projected average days of burn for major fossil fuel generating stations, if feasible. The utility shall explain substantial differences, if any, between actual Period I inventories and the target objectives, or between Period II objectives and Period I objectives. Nuclear fuel balances shall include fuel in stock, fuel in the reactor and spent fuel in the process of cooling in Accounts 120.2, 120.3, 120.4, less accumulated provisions for amortization of nuclear fuel assemblies in Account 120.5.

(B) *Plant materials and operating supplies.* The utility shall state materials and operating supply balances for each of the major electric utility operating functions of production, transmission, and distribution, and for each significant type of miscellaneous operating supplies. Miscellaneous supplies shall

be grouped to facilitate suitable allocations or assignments among utility services.

(C) *Prepayments.* The utility shall indicate prepayment balances for each major prepayment item, with a brief description of the item. Balances shall be grouped and subtotaled to facilitate suitable allocations or assignments among utility services.

(ii) *Cash working capital.* The utility shall indicate average monthly working cash requirements that reflect the extent to which day-to-day operational utility service revenues are received later or earlier than cash disbursements necessary to provide the services, with an explanation of how such requirements are derived.

(13) *Statement AM—Construction work in progress.* Statement AM is a statement of the amount of construction work in progress described according to functional classification for Period I and Period II. For production plant and transmission plant, the utility shall state the balances as of the beginning of the first month and the end of each month of both Period I and Period II, with an average of the 13 balances for each period. For each function of plant identified in Statement AD other than production or transmission, the utility shall state the balances as of the beginning and the end of both Period I and Period II, with an average of the beginning and end balances for each period. If any Period I or Period II balance is not available, the utility shall include monthly estimates and an explanation of the relevant circumstances. Pollution control facilities, fuel conversion facilities, or other construction amounts reported in Statement AG shall be excluded from amounts reported in this Statement.

(14) *Statement AN—Notes payable.* Statement AN is a statement of the electric utility portion of average notes payable for Period I and Period II. The utility shall indicate balances as of the beginning of the first month and the end of each month of both Period I and Period II, with an average of the thirteen balances for each period. If any of the Period I or Period II balances is not available or is unrepresentative of the current financing plan of the utility, the utility shall provide an explanation of the relevant circumstances. If a utility has operations other than electric, the utility shall also show allocations between electric and other utility departments on an appropriate basis, such as the average amount of construction work in progress and net plant.

(15) *Statement AO—Rate for allowance for funds used during construction.* Statement AO is a statement of the basis of the rate for computing the allowance for funds used during construction (AFUDC) for Period I and Period II.

(i) The utility shall show the computations of the maximum rates for the construction allowances computed in accordance with plant instructions of the Commission's Uniform System of Accounts, 18 CFR part 101. The utility shall show the rates computed annually, and shall provide the rates for each annual period that includes any part of Period I or Period II. If the utility proposes to use a net-of-tax rate, the utility shall show the derivation for both the gross-of-tax and net-of-tax rates.

(ii) If the book allowance amounts of AFUDC do not reflect the maximum rates for allowances for funds computed in accordance with clause (i), the utility shall show the derivation for the actual rates utilized in computing AFUDC, including derivation of any net-of-tax rate utilized by the utility.

(16) *Statement AP—Federal income tax deductions—interest.* Statement AP is a statement of electric utility interest charges for Period I and Period II. For each period, the utility shall state the total electric utility interest in terms of three or more component items described in clauses (i) through (iv).

(i) The utility shall state the allowance for borrowed funds used for electric utility construction Account 432 as a separate component. The utility shall show supporting detail, including computation of the amounts on the basis of AFUDC rates claimed in Statement AO.

(ii) The utility shall state interest for borrowed funds used for electric utility construction Account 431 as a separate component. If applicable, the utility shall also show all elements of Account 431 related to purposes other

than electric utility construction, with detailed supporting material, such as a computation of allocations between electric and other utility departments with explanatory material to support the bases of such allocations.

(iii) The utility shall state the interest on long-term debt required for electric rate base investment as a separate component. The interest amount shall be consistent with that shown and utilized in Statement BK under paragraph (h)(36) of this section.

(iv) The utility shall show other interest items appropriate in the determination of net taxable income allocable to the wholesale services at issue. The utility shall describe and support each item and shall accompany each item with a statement of the basis on which the item is allocable to the wholesale services. The utility shall also list a short descriptive title for each item.

(17) *Statement AQ—Federal income tax deductions—other than interest.* Statement AQ is a statement of other deductions from net operating income before Federal income taxes, for Period I and Period II, which deductions are appropriate in determining the net taxable income allocable to the wholesale services subject to the changed rate. The utility shall show unallowable deductions as negative entries in this statement. The utility shall itemize deductions in accordance with clause (i) through (iii) and individually identify each by a brief descriptive title.

(i) The utility shall report, as a separate component of this statement, the difference between tax and book depreciation, in total, or in individual amounts based on the Internal Revenue Code provisions that permit the utility to use various methods of computing depreciation for tax purposes, such as liberalized depreciation or the asset depreciation range. If the utility reports the differences in total only, it shall list the specific Internal Revenue Code provisions that result in the difference.

(ii) The utility shall state taxes and pensions capitalized as a separate component.

(iii) The utility shall describe and support other deduction items appropriate in the determination of net taxable income allocable to the wholesale services. Each item shall be accompanied by a brief explanation of the basis on which the item is allocable to the wholesale services.

(18) *Statement AR—Federal tax adjustments.* Statement AR is a statement of adjustments to Federal income taxes for Period I and Period II. If subaccounts are maintained to reflect differences in ratemaking treatment among regulatory authorities having jurisdiction, the utility shall provide adjustment amounts in accordance with such subaccounts. The utility shall report detailed explanations of the bases upon which the subaccounts were established and are maintained.

(i) For each major function of plant identified in Statement AD under paragraph (h)(4), the utility shall state the electric utility component adjustment for the Federal portions of the provision for deferred income tax Account 410.1. If the data are not available by function, the utility shall state the amounts for the total electric utility and shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balances obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AR the necessary data. The utility shall provide the adjustment amounts for total electric and, to the extent available for each such major functional component, accompanied by summary totals segregated in accordance with related balance sheet Accounts 281, 282, 283, and 190 [*see* Statements AF and AG]. Account 190 items require a negative sign for entries in Statement AR. The utility shall identify the summarized items by account number.

(ii) The utility shall provide for the Federal portions of the provision for deferred income tax-credit Account 411.1 the data required by clause (i) for Account 410.1.

(iii) For each major functional classification of plant identified in Statement AD under paragraph (h)(4), the utility shall provide the electric utility

component for investment tax credits generated for Period I and Period II, credits utilized for each period, and the allocations to current income for each period. If the data are not available by function, the utility shall state the amounts for total electric utility and shall describe the procedure by which the utility believes it can reasonably estimate the portion of the total electric balances for each major functional classification. The utility may show by function the component balance obtained by applying the procedure. If such estimation requires data that are not provided elsewhere in the cost of service statements in this paragraph, the utility shall supply in Statement AR the necessary data. If itemized in detail, balances shall be subtotaled for each major function, and totaled for the electric utility department. Detailed data shall be consistent with that provided in Statement AF under paragraph (h)(6) of this section.

(iv) The utility shall list and designate as other adjustment items any additional Federal income tax adjustments and shall provide a brief descriptive title for each item. The utility shall explain the reasons for inclusion of each item, and shall indicate the basis on which each will be assigned or allocated to the wholesale services subject to the changed rate and to the other electric utility services.

(19) *Statement AS—Additional state income tax deductions.* Statement AS is a listing of state income tax deductions for Period I and Period II, in addition to those listed at Statements AP and AQ for Federal tax purposes. The utility shall explain the reasons for inclusion of each item. The utility shall indicate the basis on which each item is to be assigned or allocated to the wholesale services at issue and to the other electric utility services. If applicable, the utility shall show unallowable deductions as negative entries in this statement. The utility shall provide the percentage of Federal income tax payable which is deductible for state income tax purposes, if applicable. [*See also* Statement AY, dealing with tax rate data.]

(20) *Statement AT—State tax adjustments.* Statement AT is a statement of adjustments to state income taxes for Period I and Period II. The utility shall prepare and present the data in statement AT as prescribed for Federal tax adjustments in Statement AR. The utility shall annotate Statement At data as necessary to identify state tax adjustments that are not properly deductible for Federal tax purposes.

(21) *Statement AU—Revenue credits.* Statement AU is, for Period I and Period II, a statement of the operating revenue balances in Accounts 450 through 456, and other revenue items, such as short-term sales in Account 447, that are appropriately credited to the cost of service for determinations of costs allocable to the wholesale services subject to the changed rate. The utility shall include revenue credits proposed for exclusive-use commitment of major power supply facilities according to instructions for preparation of Statement BF under paragraph (h)(31) of this section. When applicable, the utility shall state revenue taxes for each revenue credit item. The utility shall explain the reasons for inclusion of each item, and shall indicate the basis for assigning or allocating each item to the wholesale services subject to the changed rate and to the other electric utility services.

(22) *Statement AV—Rate of return.* Statement AV is a statement and explanation of the percentage rate of return requested by the utility. The utility shall provide the complete capital structure, including ratios, component costs and weighted component costs claimed by the utility. The utility shall submit additional data where any component of the capital of the utility is not primarily obtained through its own financing, but is primarily obtained from a company by which the utility is controlled, as defined in the Commission's Uniform System of Accounts, 18 CFR part 101. The utility shall submit the additional data, if required with respect to the debt capital, preferred stock capital and common stock capital of such controlling company or any intermediate company through which such funds have been secured.

(i) *General.* The utility shall show, based on the capitalization of the utility, the cost of debt capital and preferred stock capital, the claimed rate

of return on the common equity of the utility and the resulting overall rate of return requested.

(A) For Period I and, if applicable, Period II, the utility shall show in tabular form the following:

(*1*) Cost of each capital element, including claimed rate of return on equity capital;

(*2*) Capitalization amounts and ratios;

(*3*) Weighted cost of each capital element; and

(*4*) Overall claimed rate of return.

(B) When a Period II filing is submitted the utility shall provide:

(*1*) A full explanation of, and supporting work papers for, the *pro forma* adjustments to the actual capitalization data to arrive at the Period II capitalization; and

(*2*) The *pro forma* adjustment to Period I data to arrive at the Period II amount for unappropriated undistributed subsidiary earnings in Account 216.1.

(C) If not included elsewhere in the filing, the utility shall submit the amount for Account 216.1 for Period I as part of this statement.

(ii) *Debt capital.* (A) The utility shall show the weighted cost for all issues of long-term debt capital as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated for the end of Period II. The weighted cost is calculated by: (*1*) Multiplying the cost of money for each issue under clause (B)(*6*) below by the principal amount outstanding for each issue, which yields the annualized cost for each issue; and (*2*) adding the annual cost of each issue to obtain the total for all issues, which is divided by the total principal amount outstanding for all issues to obtain the weighted cost for all issues.

(B) The utility shall show the following for each class and series of long-term debt outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II.

(*1*) Title;

(*2*) Date of offering and date of maturity;

(*3*) Interest rate;

(*4*) Principal amount of issue;

(*5*) Net proceeds to the utility;

(*6*) Cost of money, which is the yield to maturity at issuance based on the interest rate and net proceeds to the utility determined by reference to any generally accepted table of bond yields;

(*7*) Principal amount outstanding;

(*8*) Name and relationship of issuer and if the debt issue was issued by an affiliate; and

(*9*) If the utility has acquired at a discount or premium some part of the outstanding debt which could be used in meeting sinking fund requirements, or for some other reason, the annual amortization of the discount or premium for each issue of debt from the date of the reacquisition over the remaining life of the debt being retired. The utility shall show separately the total discount and premium to be amortized, and the amortized amount applicable to Period I and, if applicable, Period II.

(C) The utility shall show the before-tax interest coverage, for the twelve months of Period I based on the indenture requirements. The utility shall provide a copy of the work papers used to make the calculations, with explanations appropriate to understand the calculations.

(iii) *Preferred stock and preference stock capital.* (A) This statement shall show the weighted cost for all issues of preferred and preference stock capital as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated for the end of Period II. The weighted cost is calculated by: (*1*) Multiplying the cost of money for each issue under clause (B)(*9*) by the par amount outstanding for each issue, which yields the annualized cost for each issue; and (*2*) adding the annual cost of each issue to obtain the total for all issues, which is divided by the total par amount outstanding for all issues to obtain the weighted cost for all issues.

(B) The statement shall show for each class and issue of preferred and preference stock outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II:

(*1*) Title;

(*2*) Date of offering;

(*3*) If callable, call price;

(*4*) If convertible, terms of conversion;

(*5*) Dividend rate;

(*6*) Par or stated amount of issue;

(*7*) Net proceeds to the filing utility;

(*8*) Ratio of net proceeds to gross proceeds received by the filing utility;

(*9*) Cost of money (dividend rate divided by the ratio of net proceeds to gross proceeds for each issue);

(*10*) Par or stated amount outstanding; and

(*11*) If issue is owned by an affiliate, name and relationship of owner.

(iv) *Common stock capital.* This statement shall show the following information for each sale of common stock during the five-year period preceding the date of the balance sheet for the end of Period I and for each sale of common stock between the end of Period I and the date that the changed rate is filed:

(A) Number of shares offered;

(B) Date of offering;

(C) Gross proceeds at offering price;

(D) Underwriters' commissions;

(E) Dividends per share;

(F) Net proceeds to company;

(G) Issuance expenses; and

(H) Whether issue was offered to stockholders through subscription rights or to the public and whether common stock was issued for property or for capital stock of others.

(v) *Supplementary financial data.* The utility shall submit a statement indicating the sources and uses of funds for Period I and as estimated for Period II and a copy of the utility's most recent annual report to the stockholders. The utility shall also supply a prospectus for its most recent issue of securities and a copy of the latest prospectus issued by any subsidiary of the filing utility or by any holding company of which the filing utility is a subsidiary.

(23) *Statement AW—Cost of short-term debt.* In Statement AW, the utility shall provide a statement of the cost of capital rate for short-term debt of the utility as of the end of Period I, as expected on the date the proposed rate is filed, and, if applicable, as estimated for the end of Period II, with details supporting each stated cost. The short-term debt rate shown in Statement AW shall include only the short-term debt that appears on the income statement as interest expense and shall not include nominal forms of financing, such as trust agreements.

(24) *Statement AX—Other recent and pending rate changes.* Statement AX is a statement describing the extent to which operating revenues are subject to refund for Period I and, if applicable, Period II, for each rate change filed with any Federal, state, or other regulatory body that has jurisdiction. The utility shall list and submit any orders in which applications for a rate increase have been acted on by any regulatory body during Period I, Period II, or the interval between Period I and Period II, and a copy of each transmittal letter or equivalent written document by which a utility summarized and submitted any pending applications that have not been acted on. Statement AX shall reflect information available at the time of submittal under this paragraph. Notwithstanding any other provision of this section, Statement AX is required to be filed only if the proposed rate design tracks retail rates.

(25) *Statement AY—Income and revenue tax rate data.* (i) Statement AY is a statement of tax rate data for Period I and Period II arranged as follows:

(A) Nominal Federal income tax rate;

(B) Nominal state income tax rate;

(C) Proportion of Federal income taxes payable which is deductible for state income tax purposes. If an allowable deduction is stated in other terms, the utility shall provide an estimate of the effective deduction as a percentage of Federal tax payable; and

(D) Revenue tax rate. If the revenue tax rate is scaled, the utility shall show approximate weighted average rates for relevant revenue levels and full supporting data.

(ii) If the utility serves in more than one jurisdiction for revenue or state income tax purposes, the utility shall state the appropriate tax rates for each wholesale customer group at issue and for all other customers as a composite group. [*See,* Statement BA under paragraph (h)(26) for wholesale customer grouping criteria.] If there are any changes in tax rates that occur in Period I or that may occur in Period II,

the utility shall describe such changes and the effective date of the changes.

(26) *Statement BA—Wholesale customer rate groups.* (i) Statement BA is a list of wholesale customers by group for the purpose of:

(A) Allocating the allowable costs of the utility to such customer groups on the basis of electric utility services rendered; and

(B) Comparing proposed revenues from each customer group with the cost of service as allocated to that group.

(ii) The utility shall limit the number of wholesale customer groups listed to the minimum required under the following criteria:

(A) At least one customer group shall be specified for each separate wholesale rate subject to the changed rate filing.

(B) In general, all customers proposed to be served on the same rate shall be included in a common group. If the utility believes that there are significant differences in services provided under the same rate, the utility shall subdivide the common group served by the same rate into separate customer groups characterized by the type of service provided each group and shall demonstrate whether the common rate is cost-based by means of cost-justification for each service group. Certain customer groupings, such as cooperatives or municipals, may also be utilized to facilitate purchaser evaluations of the changed rate.

(C) In all cases, the utility shall select customer groupings on a basis consistent with rate design information provided in Statement BL under paragraph (h)(37) of this section.

(iii) The utility shall enumerate all wholesale customer rate groups, together with a brief descriptive title for each group. For example:

Group 1. Full Requirements Tariff FR–1.

Group 2. Partial Requirements Tariff PR–1.

(27) *Statement BB—Allocation demand and capability data.* Statement BB is a statement of electric utility demand and capability data for Period I and Period II to be considered as a basis for allocating related costs to the wholesale services subject to the changed rate.

(i) For each month of Period I and Period II, with an average for each period, the utility shall show the maximum peak firm kilowatt demand on the power supply system of the utility, and the kilowatt demands of the wholesale services that coincide with the system monthly maximum power supply demand, including for Period I the date and hour for such coincidental peak demands. The utility shall state these kilowatt demands in terms of 60-minute intervals or other intervals adjusted to the equivalent of 60 minutes. The utility shall not include in the data the demands associated with interruptible power supply services, firm or nonfirm transmission wheeling services, or demands associated with other services the revenues from which are shown as revenue credits in Statement AU under paragraph (h)(21). The utility shall provide wholesale service demand data as follows:

(A) The wholesale service data for each individual customer delivery point or set of delivery points that constitutes an individual wholesale customer billing unit shall include demands at delivery. The individual customer wholesale service data shall be summarized and subtotaled in accordance with Statement BA customer groupings.

(B) The data supplied for each wholesale customer group under clause (A) shall be adjusted for losses to reflect demand at the power supply level. The data shall be totaled to show total customer group demand at power supply level for each month of Period I and Period II.

(ii) To the extent such data are available, the utility shall state Period I and Period II monthly maximum demand data for interruptible power supply services, firm wheeling services, and nonfirm wheeling services. The utility shall also provide, to the extent data are available, firm wheeling demand data for any of the 60-minute periods that coincide with the times of power supply peak demands shown under clause (i). The utility shall indicate the basis of all demands, such as metered demands or contract demands, reported under this clause. For interruptible services, the utility shall provide a description of the conditions

under which service may be interrupted or curtailed. The utility shall include available information on actual interruptions or curtailments during a three-year period that includes Period I. If any of the wholesale rates at issue are for interruptible or curtailable service, the utility shall provide any demand data specifically relevant to such service.

(iii) If a utility establishes plant categories in Statement AD under paragraph (h)(4) of this section for the purpose of supporting wholesale rates for firm power supply services with special characteristics, such as base load, intermediate, or peaking, the utility shall provide in Statement BB the demand data required by clause (i) in total and in separate corresponding demand values consistent with the service characteristics. Corresponding values shall be stated for the system demand of the utility, and for each applicable wholesale service group.

(iv) If a utility establishes plant categories in Statement AD under paragraph (h)(4) of this section for the purpose of supporting wholesale rates for nonfirm power supply services, such as capacity sales, the utility shall include in Statement BB for each month of Period I and Period II the monthly capability data relied on by the utility in developing costs allocable to such rates, with an explanation of the underlying cost allocation rationale.

(v) If a utility establishes production plant categories in Statement AD under paragraph (h)(4) of this section for the purpose of supporting wholesale rates based on specialized ratemaking theories such as marginal cost pricing, time-of-day pricing, or base, intermediate, and peaking characteristics, the utility shall include in Statement BB all demand and capability data relied on by the utility in developing support on a cost of service basis, with appropriate explanatory material.

(vi) For each month of Period I and Period II, the utility shall provide any additional demand data that the utility believes to be relevant to the allocation of electric utility costs to the wholesale services at issue. The utility shall fully support all such data and shall explain the rationale and the specific application proposed.

(vii) Based upon information reported in Statements BB and BC, the utility shall list selected months that are normally the months of greatest significance in determining the need of the utility for power supply capability throughout the year. All twelve months may be selected, if appropriate. In its selection, the utility shall take into account any effects of local weather seasons and, particularly, the extent to which peak demands may tend to be similar in magnitude in two or more months of a weather season. The utility shall explain the reasons for the selections and describe the significance for the selections of seasonal variations in the weather.

(28) *Statement BC—Reliability data.* Statement BC is a statement relating to reference standards of the filing utility for electric power supply reliability, and to information designed to reflect monthly availability of generating capacity reserves.

(i) For Period II, Period I, and each of the three calendar years preceding Period I, the utility shall state and briefly explain its objective reference standard of production power supply reliability and the rationale underlying its choice of a reliability standard, including whether it participates with other electric utilities in the selection of a common standard on an area or pool basis. The utility shall identify any such participating utilities, and provide a general explanation of the basis upon which the reliability standard was jointly developed.

(ii) The utility shall describe how its objective standard for production power supply reliability affects its electric generating facility construction planning and purchased power planning.

(iii) For the peak day of each month of Period II, Period I, and, to the extent data are available, for the peak day of each month of the three calendar years preceding Period I, the utility shall include tabular schedules designed to show the following:

(A) Net peak load in megawatts, itemized to show:

(*1*) Gross peak firm load, including all firm sales assured available by the reserve capacity of the utility;

(*2*) All firm purchases assured available by the reserve capacity of the supplier; and

(*3*) Net peak load, computed as gross peak load under clause (*1*) minus all firm purchases under clause (*2*).

(B) Net available dependable capacity, that is, the load-carrying ability of the electric production facilities determined for the purpose of scheduling capacity in day-to-day operations, provided in megawatts and itemized to show:

(*1*) The owned dependable capacity of the utility for each production plant category selected in Statement AD under paragraph (h)(4);

(*2*) Scheduled maintenance of owned dependable capacity of the utility;

(*3*) Purchased dependable capacity of the utility;

(*4*) Scheduled maintenance of purchased dependable capacity of the utility; and

(*5*) Net available dependable capacity, computed as the owned dependable capacity under clause (*1*), minus scheduled maintenance of owned capacity under clause (*2*), plus purchased dependable capacity under clause (*3*), minus scheduled maintenance of purchased capacity under clause (*4*).

(C) Available reserves in megawatts, which is the net available dependable capacity under clause (iii)(B) minus net peak load under clause (iii)(A).

(D) Available reserves as a percent of peak load, which is the available reserves under clause (iii)(C) divided by net peak load under clause (iii)(A).

(29) *Statement BD—Allocation energy and supporting data.* Statement BD is a statement of electric utility energy data for Period I and Period II to be considered as bases for allocating related costs to the wholesale services subject to the changed rate.

(i) For each month of Period I and Period II, and as totaled for the twelve months of each period, the utility shall show the megawatt-hours of firm power supply energy required by the system of the utility and the megawatt-hour energy requirements of the wholesale customer groups whose services will be subject to the changed rate. The wholesale service data for each individual customer delivery point or set of delivery points that constitutes an individual wholesale customer billing unit shall include megawatt-hours at delivery. The utility shall summarize and subtotal these individual customer data in accordance with Statement BA customer groupings under paragraph (h)(26). The utility shall show a loss adjustment for each wholesale customer group to reflect energy at the power supply level. The utility shall total the data to show total customer group energy requirements at power supply level for each month of Period I and Period II.

(ii) Data provided under clause (i) shall not include energy associated with interruptible or curtailable services, or energy associated with other services, the revenues from which are shown as revenue credits in Statement AU under paragraph (h)(21) of this section. The utility shall separately state Period I and Period II monthly and total energy data for any such services provided by the utility. If any of the proposed wholesale rates at issue are for interruptible or curtailable service, the utility shall provide descriptive material and energy data specifically relevant to such services.

(iii) If a utility selects subfunctional categories in Statement AD under paragraph (h)(4) of this section for the purpose of supporting any changed wholesale rate for firm power supply services with special characteristics, such as base load, intermediate, and peaking services, the utility shall separate the energy data required by clause (i) into corresponding energy values consistent with the service characteristics and consistent with energy-related expense categories utilized in Statement AH under paragraph (h)(8) of this section. The utility shall state the corresponding values for the utility's system energy and for each applicable wholesale service group.

(iv) If a utility establishes plant categories in Statement AD under paragraph (h)(4) of this section for the purpose of supporting any changed wholesale rate for nonfirm production services, or the changed wholesale rate based on specialized ratemaking theories [see paragraph (h)(27)(v) of this section], the utility shall include in Statement BD all energy data relied on by the utility in developing the support

on a cost of service basis and relevant explanatory material. Energy data provided under this clause shall be consistent with related expense categories utilized in Statement AH under paragraph (h)(8) of this section.

(v) For each month of Period I and Period II, and as totaled for the twelve months of each period, the utility shall show the megawatt-hours generated, itemized in accordance with Statement AD production subfunctional categories, and the megawatt-hours purchased or interchanged, itemized to show each type of transaction, such as firm energy or economy interchanged energy. The utility shall quantitatively reconcile such data with the system allocation energy reported in this statement, and with energy data underlying the fuel and purchased power expense reported in Statement AH.

(30) *Statement BE—Specific assignment data.* (i) Statement BE is a statement of specific components of the electric costs of service of the utility for Period I and Period II. Statement BE costs of service are those apportioned among wholesale services subject to the rate change and other utility services, on a basis other than:

(A) Demand, capability, or energy data provided in Statements BB and BD;

(B) A proportional relationship based on a selected plant category or expense item for which an allocation to wholesale services is to be independently determined; or

(C) Exclusive-use commitment in Statement BF under paragraph (h)(31) of this section.

(ii) The utility shall include specific assignments considered appropriate by the utility. Typical cost of service components that could be specifically assigned are distribution plant [*see* examples listed in Statement AD under paragraph (h)(4) of this section], certain total electric wages and salaries provided in Statement AI under paragraph (h)(9) of this section, such as wages and salaries for customer accounting and for customer service and information, and certain administrative and general expense items. [*See* examples listed in Statement AH under paragraph (h)(8) of this section.]

(iii) The utility shall limit specific assignments to the minimum required to adequately provide for costs not otherwise appropriately allocable.

(iv) For each specific assignment, the utility shall include at least the following information:

(A) Brief descriptive component title, such as *distribution substations* or *rate case expenses*;

(B) Total electric amount in dollars;

(C) Wholesale customer group dollar amounts stated individually for each wholesale customer rate group identified in Statement BA under paragraph (h)(26), and stated in total for all such groups; and

(D) Explanation of the basis on which assignments were made, accompanied by supporting detailed computations.

(31) *Statement BF—Exclusive-use commitments of major power supply facilities.* Statement BF is a statement describing and justifying the commitment to exclusive-use for particular services of all or a stated portion of electric utility generation units or plants, or major transmission facilities.

(i) For Period I and Period II, the utility shall list each transaction in which all or a stated portion of the output of a specified filing utility-owned generating unit or group of units was committed exclusively to a particular customer or group of customers, or to a power pool or similar power supply entity. For each such transaction, the utility shall provide the following information:

(A) Brief descriptive title for each commitment;

(B) Name of plant and unit designation;

(C) Name of the purchaser or power pool or other similar power supply entity;

(D) Duration of the transaction;

(E) Basis of rates or charges, stated in terms of whether a transaction reflects marginal, incremental, or fully distributed costs, the specific overall and common equity rates of return included in costs, provided on both a claimed and earned basis to the extent such information is available, the approximate date of the cost analysis on which the rates and charges were based, and any other considerations significant to the transaction;

(F) Revenue received for each month of Period I and Period II or, if applicable, monthly quantities of power and energy received or available from power pools as consideration for commitment to a pool; and

(G) Proposed treatment in the cost of service determinations for the wholesale services at issue. For example, a credit of revenue to the total electric cost of service, in Statement AU under paragraph (h)(21), could be proposed to account for unit capacity sales based upon incremental capital costs. The utility shall include explanatory material and support for the proposed procedures.

(ii) For Period I and Period II, the utility shall list each transaction in which all, or a portion, of a major transmission facility owned by the filing utility was committed exclusively to a particular customer or group of customers. For each such transaction, the utility shall provide information similar to that required by clause (i).

(32) *Statement BG—Revenue data to reflect changed rates.* Statement BG is a statement of revenues for Period I and Period II, including those under the changed rate for the wholesale services at issue.

(i) For each month of Period I and Period II, and in total for each of the two periods, the utility shall show all billing determinants and metered quantities for each delivery point or set of delivery points that constitutes an individual wholesale customer billing unit, and the result of applying each specific rate component to the billing determinants for each billing unit stated with the total of the computed monthly bill for the customer. If the rates include a fuel clause, the utility shall compute and total the revenues under the fuel clause to reflect fuel costs incurred during each month of Period I and Period II. That is, the fuel clause revenues for the first month of Period I shall reflect fuel costs incurred for that month, and so on for each month of Period I and Period II. In computing fuel clause revenues, the utility shall determine fuel cost according to § 35.14 of this chapter.

(ii) If the form of the proposed fuel clause would produce revenues different from those computed in accordance with clause (i), the utility shall separately compute and state such fuel clause revenues for each customer for each month of Period I and Period II.

(iii) The utility shall summarize separately revenue data computed in accordance with clauses (i) and (ii) above for each month and in total for Period I and Period II, in accordance with wholesale rate groups specified in Statement BA under paragraph (h)(26) of this section. The utility shall show total electric department revenues for each period to include revenues under the changed rate for all such wholesale customer rate groups.

(iv) For Period I and as estimated for Period II, the utility shall summarize all billing determinants and revenues received from interruptible or curtailable services. Billing determinants and revenue data shall be consistent with interruptible demand and energy data in Statements BB and BD. The utility shall include an explanation of the extent to which interruptible or curtailable service revenues are or are not included in revenue credits in Statement AU under paragraph (h)(21) of this section.

(33) *Statement BH—Revenue data to reflect present rates.* Statement BH is a statement of revenues for Period I and Period II, including those under present rates for wholesale services at issue, and for total electric service to reflect such revenues for wholesale services. The utility shall prepare this statement to include data consistent with criteria specified for presentation of revenue under the changed rate in Statement BG under paragraph (h)(32) of this section.

(34) *Statement BI—Fuel cost adjustment factors.* Statement BI is a statement of monthly fuel cost adjustment factors under the changed rate and under the present rates, for Period I and Period II.

(i) If the changed rate schedule embodies a fuel cost adjustment clause, the utility shall show detailed derivations of fuel cost adjustment factors computed to reflect fuel cost incurred during each month of Period I and Period II. Fuel cost adjustment factors are those required for revenue determinations in accordance with paragraph (h)(32)(i) of Statement BG.

(ii) If additional proposed fuel clause revenue data are reported in accordance with paragraph (h)(32)(ii) of Statement BG, the utility shall show detailed derivation of applicable monthly fuel adjustment factors.

(iii) If the present rate includes a fuel cost adjustment change, the utility shall show detailed derivations of fuel cost adjustment factors for each month of Period I and Period II. The utility shall include in Statement BI derivations for all monthly factors required in the computation of present fuel clause revenues reported in Statement BH. The utility shall provide an explanation of the differences between the present and proposed fuel clauses.

(iv) All fuel cost adjustment factors shall be cost-based. The utility shall make a computational showing that shall develop adjustment factors in a manner consistent with the requirements of §35.14 of this chapter. The utility shall provide supporting detail on cost by type of fuel, and shall show separately the allowable fuel clause cost component of purchased or interchanged energy. All fuel cost data shall be consistent with that included in operation and maintenance expenses in Statement AH under paragraph (h)(8) of this section.

(35) *Statement BJ—Summary data tables.* Statement BJ is a tabular summary of portions of Period I and Period II data from specific cost of service statements in this paragraph. The utility shall summarize under descriptive titles the Period I and Period II data from the cost of service provisions listed in this subparagraph. The utility shall supply the data in the manner described for each cost of service statement and in this subparagraph.

(i) If a utility provides in Statement BK information that is substantially equivalent to the information required in this statement, the utility may fulfill the requirements of this statement by specifically referring to the location in Statement BK of the information required in this subparagraph.

(ii) The utility shall provide the information in the following statements as average total electric department monthly balances for each function and subfunction of plant:

(A) Statement AD—(h)(4)(i) and (ii);

(B) Statement AE—(h)(5)(i) and (ii);

(C) Statement AF—(h)(6)(i) through (v);

(D) Statement AG—(h)(7)(i) through (vi);

(E) Statement AL—(h)(12)(i) and (ii);

(F) Statement AM—(h)(13); and

(G) Statement AN—(h)(14).

(iii) The utility shall provide the information in the following statements as total electric department annual revenue and expense amounts:

(A) Statement AH—(h)(8)(i), (iv) and (v);

(B) Statement AI—(h)(9)(i) and (ii);

(C) Statement AJ—(h)(10)(i);

(D) Statement AK—(h)(11)(i);

(E) Statement AP—(h)(16)(i) through (iv);

(F) Statement AQ—(h)(17)(i) through (iii);

(G) Statement AR—(h)(18)(i) through (iv);

(H) Statement AS—(h)(19);

(I) Statement AT—(h)(20); and

(J) Statement AU—(h)(21).

(iv) The utility shall provide all cost of capital amounts in the following statements.

(A) Statement AV—(h)(22)(i)(A); and

(B) Statement AW—(h)(23);

(v) The utility shall provide all tax rate data in Statement AY, paragraph (h)(25)(i) of this section.

(vi) The utility shall provide the information in the following statements as appropriate, for total electric department values and individual customer group values:

(A) Statement BB—(h)(27)(i) through (vi);

(B) Statement BD—(h)(29)(i) through (iv);

(C) Statement BE—(h)(30)(iv) (A), (B), and (C);

(D) Statement BG—(h)(32)(iii); and

(E) Statement BH—(h)(33).

(36) *Statement BK—Electric utility department cost of service, total and as allocated.* Statement BK is a statement of the claimed fully allocated cost of service of the utility developed and shown for Period I and Period II. The utility shall include analytical support for each rate proposed to be differentiated on a time-of-use basis. The utility shall also provide any marginal or incremental cost information that is required to support the changed rate

developed on a marginal or incremental cost basis. The utility shall show allocations of fully distributed costs to the wholesale services subject to the changed rate accompanied by a comparison of allocated costs with revenues under the changed rate. Nothing in this subparagraph shall preclude use by any utility of any cost of service technique it believes reasonable and that is consistent with the requirements of paragraph (g) of this section.

(i) The utility shall base the fully distributed cost of service and the allocations thereof upon data provided in the accompanying detailed statements required under this section and additional data which the utility may submit and support in connection with this statement. The cost of service data of the utility shall conform to the following requirements:

(A) The total electric rate base and cost of service shall be itemized and summarized by major functions and in a format designed to facilitate review and analysis.

(B) Based on the total electric rate base and cost of service, and on allocated or assigned component elements, the cost of service for each Statement BA wholesale customer rate group under paragraph (h)(26) shall be itemized and summarized by major functions in a format consistent with that shown for total electric.

(C) The costs of service data for total electric and for each of the wholesale customer groups shall include data that show the return and the income taxes by components and in total, based upon the rate of return claimed by the utility in Statement AV under paragraph (h)(22). Individual components of income taxes shall include income taxes payable, provision for deferred income tax—debits and deferred income tax—credits, investment tax credits, or other adjustments.

(D) The fully distributed cost of service study of the utility shall disclose the principal determinants for allocation of total electric costs among the wholesale customer groups, including but not limited to the following:

(*1*) Computations showing the energy responsibilities of the wholesale services, with supporting detail;

(*2*) Computations showing the demand responsibilities of the wholesale services, with supporting detail; and

(*3*) Computations showing the specific assignment responsibilities of the wholesale services, with supporting detail.

(ii) For the total electric service and for each wholesale customer rate group, the utility shall compare the fully distributed cost of service with the revenues under the changed rate. Based on the comparison, the utility shall show the revenue excess or deficiency and the earned rate of return computed for the total electric service and for each wholesale customer rate group.

(iii) For any filing that contains Period II data, the utility shall supply any work papers and additional explanatory material necessary to support Statement BK, indexed, referenced and paginated as provided in paragraph (d)(5) of this section.

(iv) The utility shall provide a tabular comparison of Period II total electric fully distributed cost items with those of Period I. The comparisons shall show item amounts for each of the two periods, and also shall show Period II item amounts as percentages of equivalent items for Period I. Comparisons shall include at least the following items, accompanied by explanatory notes with respect to significant variations among the comparative percentages:

(A) Rate base;

(B) Production expenses;

(C) Transmission expenses;

(D) Customer accounting, customer service and information, and sales expenses;

(E) Depreciation expenses;

(F) Taxes except income and revenue;

(G) Income taxes;

(H) Revenue taxes; and

(I) Return claimed.

(37) *Statement BL—Rate design information.* In support of the design of the changed rate, the utility shall submit the following material:

(i) A narrative statement describing and justifying the objectives of the design of the changed rate. If the purpose of the rate design is to reflect costs, the utility shall state how that objective is achieved, and shall accompany

it with a summary cost analysis that would justify the rate design, including any discounts or surcharges based on delivery voltage level or other specific considerations. Such summary cost analysis shall be consistent with, derived from, and cross-referenced to the data in cost of service Statement BK. If the rate design is not intended to reflect costs, whether fully distributed, marginal, incremental, or other, the utility shall provide a statement to justify the departure from cost-based rates.

(ii) If the billing determinants, such as quantities of demand, energy, or delivery points, are on different bases than the cost allocation determinants supporting such charges, the utility shall submit an explanation setting forth the economic or other considerations that warrant such departure. The information shall include at least the following:

(A) If the individual rate for the demand, energy and customer charges do not correspond to the comparable cost classifications supporting such charges, a detailed explanation stating the reasons for the differences.

(B) If the changed rate contains more than one demand or energy block, a detailed explanation indicating the rationale for the blocking and the considerations upon which such blocking is based, including adequate cost support for the specified blocking.

(38) *Statement BM—Construction program statement.* Statement BM is a summary of data and supporting assumptions relating to the economics of any construction program to replace or expand the utility's power supply that shall be filed if the utility is filing for construction work in progress in rate base under §35.26(c)(3) of this chapter. The filing utility shall describe generally its program for providing reliable and economic power for the period beginning with the date of the filing and ending with the tenth year after the test period. The statement shall include an assessment of the relative costs of adopting alternative strategies including an analysis of alternative production plant, *e.g.,* cogeneration, small power production, heightened load management and conservation efforts, additions to transmission plant or increased purchases of power, and an explanation of why the program adopted is prudent and consistent with a least-cost energy supply program.

(Federal Power Act, 16 U.S.C. 791–828c; Dept. of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 42 FR 46267, 3 CFR 142 (1978); Pub. L. 96–511, 94 Stat. 2812 (44 U.S.C. 3501 *et seq.*))

[Order 91, 45 FR 46363, July 10, 1980]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting §35.13, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov*.

Subpart C—Other Filing Requirements

§35.14 Fuel cost and purchased economic power adjustment clauses.

(a) Fuel adjustment clauses (fuel clause) which are not in conformity with the principles set out below are not in the public interest. These regulations contemplate that the filing of proposed rate schedules, tariffs or service agreements which embody fuel clauses failing to conform to the following principles may result in suspension of those parts of such rate schedules, tariffs, or service agreements:

(1) The fuel clause shall be of the form that provides for periodic adjustments per kWh of sales equal to the difference between the fuel and purchased economic power costs per kWh of sales in the base period and in the current period:

Adjustment Factor = $Fm/Sm-Fb/Sb$

Where: F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and S is the kWh sales in the base and current periods, all as defined below.

(2) Fuel and purchased economic power costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

(ii) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (a)(2)(iii) of this section.

(iii) The total cost of the purchase of economic power, as defined in paragraph (a)(11) of this section, if the reserve capacity of the buyer is adequate independent of all other purchases where non-fuel charges are included in either F_b or F_m;

(iv) Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost;

(v) *And less* the cost of fossil and nuclear fuel recovered through all inter-system sales.

(3) Sales (S) must be all kWh's sold, excluding inter-system sales. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of: (i) Generation, (ii) purchases, (iii) exchange received, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (a)(2)(iv) of this section, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(7) Where the cost of fuel includes fuel from company-owned or controlled[1] sources, that fact shall be noted and described as part of any filing. Where the utility purchases fuel from a company-owned or controlled source, the price of which is subject to the jurisdiction of a regulatory body, and where the price of such fuel has been approved by that regulatory body, such costs shall be presumed, subject to rebuttal, to be reasonable and includable in the adjustment clause. If the current price, however, is in litigation and is being collected subject to refund, the utility shall so advise the Commission and shall keep a separate account of such amounts paid which are subject to refund, and shall advise the Commission of the final disposition of such matter by the regulatory body having jurisdiction. With respect to the price of fuel purchases from company-owned or controlled sources pursuant to contracts which are not subject to regulatory authority, the utility company shall file such contracts and amendments thereto with the Commission for its acceptance at the time it files its fuel clause or modification thereof. Any subsequent amendment to such contracts shall likewise be filed with the Commission as a rate schedule change and may be subject to suspension under section 205 of the Federal Power Act. Fuel charges by affiliated companies which do not appear to be reasonable may result in the suspension of the fuel adjustment clause or cause an investigation thereof to be made by the Commission on its own motion under section 206 of the Federal Power Act.

(8) All rate filings which contain a proposed new fuel clause or a change in an existing fuel clause shall conform such clauses with the regulations. Within one year of the effectiveness of this rulemaking, all public utilities with rate schedules that contain a fuel clause should conform such clauses with the regulations. Recognizing that individual public utilities may have special operating characteristics that may warrant granting temporary delays in the implementation of the regulations, the Commission may, upon showing of good cause, waive the requirements of this section of the regulations for an additional one-year period so as to permit the public utilities sufficient time to adjust to the requirements.

[1] As defined in the Commission's Uniform System of Accounts 18 CFR part 101, Definitions 5B.

(9) All rate filings containing a proposed new fuel clause or change in an existing fuel clause shall include:

(i) A description of the fuel clause with detailed cost support for the base cost of fuel and purchased economic power or energy.

(ii) Full cost of service data unless the utility has had the rate approved by the Commission within a year, provided that such cost of service may not be required when an existing fuel cost adjustment clause is being modified to conform to the Commission's regulations.

(10) Whenever particular circumstances prevent the use of the standards provided for herein, or the use thereof would result in an undue burden, the Commission may, upon application under § 385.207 of this chapter and for good cause shown, permit deviation from these regulations.

(11) For the purpose of paragraph (a)(2)(iii) of this section, the following definitions apply:

(i) *Economic power* is power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the buyer's total avoided variable cost.

(ii) *Total cost of the purchase* is all charges incurred in buying economic power and having such power delivered to the buyer's system. The total cost includes, but is not limited to, capacity or reservation charges, energy charges, adders, and any transmission or wheeling charges associated with the purchase.

(iii) *Total avoided variable cost* is all identified and documented variable costs that would have been incurred by the buyer had a particular purchase not been made. Such costs include, but are not limited to, those associated with fuel, start-up, shut-down or any purchases that would have been made in lieu of the purchase made.

(12) For the purpose of paragraph (a)(2)(iii) of this section, the following procedures and instructions apply:

(i) A utility proposing to include purchase charges other than those for fuel or energy in fuel and purchased economic power costs (*F)* under paragraph (a)(2)(iii) of this section shall amend its fuel cost adjustment clause so that it is consistent with paragraphs (a)(1) and (a)(2)(iii) of this section. Such amendment shall state the system reserve capacity criteria by which the system operator decides whether a reliability purchase is required. Where the utility filing the statement is required by a State or local regulatory body (including a plant site licensing board) to file a capacity criteria statement with that body, the system reserve capacity criteria in the statement filed with the Commission shall be identical to those contained in the statement filed with the State or local regulatory body. Any utility that changes its reserve capacity criteria shall, within 45 days of such change, file an amended fuel cost and purchased economic power adjustment clause to incorporate the new criteria.

(ii) Reserve capacity shall be deemed adequate if, at the time a purchase was initiated, the buyer's system reserve capacity criteria were projected to be satisfied for the duration of the purchase without the purchase at issue.

(iii) The total cost of the purchase must be projected to be less than total avoided variable cost, at the time a purchase was initiated, before any nonfuel purchase charge may be included in F_m.

(iv) The purchasing utility shall make a credit to F_m after a purchase terminates if the total cost of the purchase exceeds the total avoided variable cost. The amount of the credit shall be the difference between the total cost of the purchase and the total avoided variable cost. This credit shall be made in the first adjustment period after the end of the purchase. If a utility fails to make the credit in the first adjustment period after the end of the purchase, it shall, when making the credit, also include in F_m interest on the amount of the credit. Interest shall be calculated at the rate required by § 35.19a(a)(2)(iii) of this chapter, and shall accrue from the date the credit should have been made under this paragraph until the date the credit is made.

(v) If a purchase is made of more capacity than is needed to satisfy the buyer's system reserve capacity criteria because the total costs of the extra capacity and associated energy are less than the buyer's total avoided variable costs for the duration of the

purchase, the charges associated with the non-reliability portion of the purchase may be included in *F*.

(Approved by the Office of Management and Budget under control number 1902–0096)

(Federal Power Act, 16 U.S.C. 824d, 824e and 825h (1976 & Supp. IV 1980); Department of Energy Organization Act, 42 U.S.C. 7171, 7172 and 7173(c) (Supp. IV 1980); E.O. 12009, 3 CFR part 142 (1978); 5 U.S.C. 553 (1976))

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 421, 36 FR 3047, Feb. 17, 1971; 39 FR 40583, Nov. 19, 1974; Order 225, 47 FR 19056, May 3, 1982; Order 352, 48 FR 55436, Dec. 13, 1983; 49 FR 5073, Feb. 10, 1984; Order 529, 55 FR 47321, Nov. 13, 1990; Order 600, 63 FR 53809, Oct. 7, 1998; Order 714, 73 FR 57532, Oct. 3, 2008; 73 FR 63886, Oct. 28, 2008]

§ 35.15 Notices of cancellation or termination.

(a) *General rule.* When a rate schedule, tariff or service agreement or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule, tariff or service agreement or part thereof is to be filed in its place, a filing must be made to cancel such rate schedule, tariff or service agreement or part thereof at least sixty days but not more than one hundred-twenty days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice, each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been provided. For good cause shown, the Commission may by order provide that the notice of cancellation or termination shall be effective as of a date prior to the date of filing or prior to the date the filing would become effective in accordance with these rules.

(b) *Applicability.* (1) The provisions of paragraph (a) of this section shall apply to all contracts for unbundled transmission service and all power sale contracts:

(i) Executed prior to July 9, 1996; or

(ii) If unexecuted, filed with the Commission prior to July 9, 1996.

(2) Any power sales contract executed on or after July 9, 1996 that is to terminate by its own terms shall not be subject to the provisions of paragraph (a) of this section.

(c) *Notice.* Any public utility providing jurisdictional services under a power sales contract that is not subject to the provisions of paragraph (a) of this section shall notify the Commission of the date of the termination of such contract within 30 days after such termination takes place.

[Order 888, 61 FR 21692, May 10, 1996, as amended by Order 714, 73 FR 57532, Oct. 3, 2008]

§ 35.16 Notice of succession.

Whenever the name of a public utility is changed, or its operating control is transferred to another public utility in whole or in part, or a receiver or trustee is appointed to operate any public utility, the exact name of the public utility, receiver, or trustee which will operate the property thereafter shall be filed within 30 days thereafter with the Commission with a tariff consistent with the electronic filing requirements in § 35.7 of this part.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57533, Oct. 3, 2008]

§ 35.17 Withdrawals and amendments of rate schedule, tariff or service agreement filings.

(a) *Withdrawals of rate schedule, tariff or service agreement filings prior to Commission action.* (1) A public utility may withdraw in its entirety a rate schedule, tariff or service agreement filing that has not become effective and upon which no Commission or delegated order has been issued by filing a withdrawal motion with the Commission. Upon the filing of such motion, the proposed rate schedule, tariff or service agreement sections will not become effective under section 205(d) of the Federal Power Act in the absence of Commission action making the rate schedule, tariff or service agreement filing effective.

(2) The withdrawal motion will become effective, and the rate schedule, tariff or service agreement filing will be deemed withdrawn, at the end of 15 days from the date of filing of the withdrawal motion, if no answer in opposition to the withdrawal motion is filed

within that period and if no order disallowing the withdrawal is issued within that period. If an answer in opposition is filed within the 15 day period, the withdrawal is not effective until an order accepting the withdrawal is issued.

(b) *Amendments or modifications to rate schedule, tariff or service agreement sections prior to Commission action on the filing.* A public utility may file to amend or modify, and may file a settlement that would amend or modify, a rate schedule, tariff or service agreement section contained in a rate schedule, tariff or service agreement filing that has not become effective and upon which no Commission or delegated order has yet been issued. Such filing will toll the notice period in section 205(d) of the Federal Power Act for the original filing, and establish a new date on which the entire filing will become effective, in the absence of Commission action, no earlier than 61 days from the date of the filing of the amendment or modification.

(c) *Withdrawal of suspended rate schedules, tariffs, or service agreements, or parts thereof.* Where a rate schedule, tariff, or service agreement, or part thereof has been suspended by the Commission, it may be withdrawn during the period of suspension only by special permission of the Commission granted upon application therefor and for good cause shown. If permitted to be withdrawn, any such rate schedule, tariff, or service agreement may be refiled with the Commission within a one-year period thereafter only with special permission of the Commission for good cause shown.

(d) *Changes in suspended rate schedules, tariffs, or service agreements, or parts thereof.* A public utility may not, within the period of suspension, file any change in a rate schedule, tariff, or service agreement, or part thereof, which has been suspended by order of the Commission except by special permission of the Commission granted upon application therefor and for good cause shown.

(e) *Changes in rate schedules or tariffs or parts thereof continued in effect and which were proposed to be changed by the suspended filing.* A public utility may not, within the period of suspension, file any change in a rate schedule or tariff or part thereof continued in effect by operation of an order of suspension and which was proposed to be changed by the suspended filing, except by special permission of the Commission granted upon application therefor and for good cause shown.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57533, Oct. 3, 2008; 74 FR 55770, Oct. 29, 2009]

§ 35.18 Asset retirement obligations.

(a) A public utility that files a rate schedule, tariff or service agreement under § 35.12 or § 35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.

(b) A public utility seeking to recover nonrate base costs related to asset retirement costs in rates must provide, with its filing under § 35.12 or § 35.13, a detailed study supporting the amounts proposed to be collected in rates.

(c) A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

[Order 631, 68 FR 19619, Apr. 21, 2003, as amended by Order 714, 73 FR 57533, Oct. 3, 2008]

§ 35.19 Submission of information by reference.

If all or any portion of the information called for in this part has already been submitted to the Commission, substantially in the form prescribed

above, specific reference thereto may be made in lieu of re-submission in response to the requirements of this part.

§ 35.19a Refund requirements under suspension orders.

(a) *Refunds.* (1) The public utility whose proposed increased rates or charges were suspended shall refund at such time in such amounts and in such manner as required by final order of the Commission the portion of any increased rates or charges found by the Commission in that suspension proceeding not to be justified, together with interest as required in paragraph (a)(2) of this section.

(2) Interest shall be computed from the date of collection until the date refunds are made as follows:

(i) At a rate of seven percent simple interest per annum on all excessive rates or charges held prior to October 10, 1974;

(ii) At a rate of nine percent simple interest per annum on all excessive rates or charges held between October 10, 1974, and September 30, 1979; and

(iii)(A) At an average prime rate for each calendar quarter on all excessive rates or charges held (including all interest applicable to such rates or charges) on or after October 1, 1979. The applicable average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the *Federal Reserve Bulletin,* or in the Federal Reserve's ''Selected Interest Rates'' (Statistical Release H. 15), for the fourth, third, and second months preceding the first month of the calendar quarter.

(B) The interest required to be paid under clause (iii)(A) shall be compounded quarterly.

(3) Any public utility required to make refunds pursuant to this section shall bear all costs of such refunding.

(b) *Reports.* Any public utility whose proposed increased rates or charges were suspended and have gone into effect pending final order of the Commission pursuant to section 205(e) of the Federal Power Act shall keep accurate account of all amounts received under the increased rates or charges which became effective after the suspension period, for each billing period, specifying by whom and in whose behalf such amounts are paid.

[44 FR 53503, Sept. 14, 1979, as amended at 45 FR 3889, Jan. 21, 1980; Order 545, 57 FR 53990, Nov. 16, 1992; 74 FR 54463, Oct. 22, 2009]

§ 35.21 Applicability to licensees and others subject to section 19 or 20 of the Federal Power Act.

Upon further order of this Commission issued upon its own motion or upon complaint or request by any person or State within the meaning of sections 19 or 20 of the Federal Power Act, the provisions of §§ 35.1 through 35.19 shall be operative as to any licensee or others who are subject to this Commission's jurisdiction in respect to services and the rates and charges of payment therefor by reason of the requirements of sections 19 or 20 of the Federal Power Act. The requirement of this section for compliance with the provisions of §§ 35.1 through 35.19 shall be in addition to and independent of any obligation for compliance with those regulations by reason of the provisions of sections 205 and 206 of the Federal Power Act. For purposes of applying this section *Electric Service* as otherwise defined in § 35.2(a) shall mean: Services to customers or consumers of power within the meaning of sections 19 or 20 of the Federal Power Act which may be comprised of various classes of capacity and energy and/or transmission services subject to the jurisdiction of this Commission. *Electric Service* shall include the utilization of facilities owned or operated by any licensee or others to effect any of the foregoing sales or services whether by leasing or other arrangements. As defined herein *Electric Service* is without regard to the form of payment or compensation for the sales or services rendered, whether by purchase and sale, interchange, exchange, wheeling charge, facilities charge, rental or otherwise. For purposes of applying this section, *Rate Schedule* as otherwise defined in § 35.2(b) shall mean: A statement of

(1) Electric service as defined in this § 35.21,

(2) Rates and charges for or in connection with that service, and

(3) All classifications, practices, rules, regulations, or contracts which

in any manner affect or relate to the aforementioned service, rates and charges. This statement shall be in writing and may take the physical form of a contractual document, purchase or sale agreement, lease of facilities, tariff[5] or other writing. Any oral agreement or understanding forming a part of such statement shall be reduced to writing and made a part thereof.

[Order 271, 28 FR 10573, Oct. 2, 1963, as amended by Order 714, 73 FR 57533, Oct. 3, 2008]

§ 35.22 Limits for percentage adders in rates for transmission services; revision of rate schedules, tariffs or service agreements.

(a) *Applicability*. This section applies to all electric rate schedules, tariffs or service agreements required to be filed under this part that are used for transactions in which the utility or system performs a transmission or purchase and resale function.

(b) *Definition*. For purposes of this section, *purchased power price* means the amount paid by a utility or system that performs a transmission or purchase and resale function for electric power generated by another utility or system.

(c) *General rule*. (1) If a utility or system uses a rate component that recovers revenues computed wholly or in part as a percentage of the purchased power price, the utility or system shall establish a limit on the revenues recovered by such rate component in any transaction, in accordance with paragraph (d) of this section.

(2) The limit established under this paragraph shall be stated in mills per kilowatt-hour.

(d) *Cost support information*. (1) A utility or system shall submit cost support information to justify any revenue limit established under paragraph (c) of this section, except as provided in paragraph (e) of this section.

(2) The information submitted under this section shall consist of those costs, other than the purchased power price, incurred by a utility or system as a result of a transmission or purchase and resale transaction, which costs are not recovered under any other rate component.

[5] See § 35.2.

(e) *Exception*. A utility or system need not submit the cost support information required under paragraph (d) of this section if the limit established under paragraph (c) of this section is not more than one mill per kilowatt-hour.

(f) *Revision of rate schedules, tariffs or service agreements*. Every utility or system shall:

(1) Amend any rate schedule, tariffs or service agreements to indicate any limit established pursuant to this section, not later than 60 days after the effective date of this rule; and

(2) Hereafter conform any rate or rate change filed under this part to the requirements of this section.

(Federal Power Act, as amended, 16 U.S.C. 792–828c; Department of Energy Organization Act, 42 U.S.C. 7101–7352; E.O. 12009, 3 CFR 142 (1978))

[Order 84, 45 FR 31300, May 13, 1980. Redesignated by Order 545, 57 FR 53990, Nov. 16, 1992, as amended by Order 714, 73 FR 57533, Oct. 3, 2008]

§ 35.23 General provisions.

(a) *Applicability*. This subpart applies to any wholesale sale of electric energy in a coordination transaction by a public utility if that sale requires the use of an emissions allowance.

(b) *Implementation Procedures*. (1) If a public utility has a coordination rate schedule on file that expressly provides for the recovery of all incremental or out-of-pocket costs, such utility may make an abbreviated rate filing detailing how it will recover emissions allowance costs. Such filing must include the following: the index or combination of indices to be used; the method by which the emission allowance amounts will be calculated; timing procedures; how inconsistencies, if any, with dispatch criteria will be reconciled; and how any other rate impacts will be addressed. In addition, a utility making an abbreviated filing must:

(i) Clearly identify the filing as being limited to an amendment to a coordination rate to reflect the cost of emissions allowances, in the first paragraph of the letter of transmittal accompanying the filing;

(ii) Submit the revisions in accordance with § 35.7; and

(iii) Identify each rate schedule to which the amendment applies.

(2) The abbreviated filing must apply consistent treatment to all coordination rate schedules. If the filing does not apply consistent rate treatment, the public utility must explain why it does not do so.

(3) If a public utility wants to charge incremental costs for emissions allowances, but its rate schedule on file with the Commission does not provide for the recovery of all incremental costs, the selling public utility may submit an abbreviated filing if all customers agree to the rate change. If customers do not agree, the selling public utility must tender its emissions allowance proposal in a separate section 205 rate filing, fully justifying its proposal.

[59 FR 65938, Dec. 22, 1994, as amended by Order 714, 73 FR 57533, Oct. 3, 2008]

§ 35.24 Tax normalization for public utilities.

(a) *Applicability*. (1) Except as provided in subparagraph (2) of this paragraph, this section applies, with respect to rate schedules filed under §§ 35.12 and 35.13 of this part, to the ratemaking treatment of the tax effects of all transactions for which there are timing differences.

(2) This section does not apply to the following timing differences:

(i) Differences that result from the use of accelerated depreciation;

(ii) Differences that result from the use of Class Life Asset Depreciation Range (ADR) provisions of the Internal Revenue Code;

(iii) Differences that result from the use of accelerated amortization provisions on certified defense and pollution control facilities;

(iv) Differences that arise from recognition of extraordinary property losses as a current expense for tax purposes but as a deferred and amortized expense for book purposes;

(v) Differences that arise from recognition of research, development, and demonstration expenditures as a current expense for tax purposes but as a deferred and amortized expense for book purposes;

(vi) Differences that result from different tax and book reporting of deferred gains or losses from disposition of utility plant;

(vii) Differences that result from the use of the Asset Guideline Class ''Repair Allowance'' provision of the Internal Revenue Code;

(viii) Differences that result from recognition of purchased gas costs as a current expense for tax purposes but as a deferred expense for book purposes.

(*See* Order 13, issued October 18, 1978; Order 203, issued May 29, 1958; Order 204, issued May 29, 1958; Order 404, issued May 15, 1970; Order 408, issued August 26, 1970; Order 432, issued April 23, 1971; Order 504, issued February 11, 1974; Order 505, issued February 11, 1974; Order 566, issued June 3, 1977; Opinion 578, issued June 3, 1970; and Opinion 801, issued May 31, 1977.)

(b) *General rules*—1) *Tax normalization required*. (i) A public utility must compute the income tax component of its cost of service by using tax normalization for all transactions to which this section applies.

(ii) Except as provided in paragraph (c) of this section, application of tax normalization by a public utility under this section to compute the income tax component will not be subject to case-by-case adjudication.

(2) *Reduction of, and addition to, rate base*. (i) The rate base of a public utility using tax normalization under this section must be reduced by the balances that are properly recordable in Account 281, ''Accumulated deferred income taxes-accelerated amortization property;'' Account 282, ''Accumulated deferred income taxes—other property;'' and Account 283, ''Accumulated deferred income taxes—other.'' Balances that are properly recordable in Account 190, ''Accumulated deferred income taxes,'' must be treated as an addition to rate base.

(ii) Such rate base reductions or additions must be limited to deferred taxes related to rate base, construction or other jurisdictional activities.

(iii) If a public utility uses an approved purchased gas adjustment clause or a research, development and demonstration tracking clause, the rate base reductions or additions required under this subparagraph must apply only to the extent that the balances in Account 190 and Accounts 281 through 283 are not used, for purposes

of calculating carrying charges, as an offset to balances properly recordable in Account 188, ''Research development and demonstration expenditures,'' or Account 191, ''Unrecovered purchased gas costs.''

(c) *Special rules.* (1) This paragraph applies:

(i) If the public utility has not provided deferred taxes in the same amount that would have accrued had tax normalization been applied for the tax effects of timing difference transactions originating at any time prior to the test period; or

(ii) If, as a result of changes in tax rates, the accumulated provision for deferred taxes becomes deficient in or in excess of amounts necessary to meet future tax liabilities as determined by application of the current tax rate to all timing difference transactions originating in the test period and prior to the test period.

(2) The public utility must compute the income tax component in its cost of service by making provision for any excess or deficiency in deferred taxes described in subparagraphs (1)(i) or (1)(ii) of this paragraph.

(3) The public utility must apply a Commission-approved ratemaking method made specifically applicable to the public utility for determining the cost of service provision described in subparagraph (2) of this paragraph. If no Commission-approved ratemaking method has been made specifically applicable to the public utility, then the public utility must use some ratemaking method for making such provision, and the appropriateness of this method will be subject to case-by-case determination.

(d) *Definitions.* For purposes of this section, the term:

(1) *Tax normalization* means computing the income tax component as if the amounts of timing difference transactions recognized in each period for ratemaking purposes were also recognized in the same amount in each such period for income tax purposes.

(2) *Timing differences* means differences between amounts of expenses or revenues recognized for income tax purposes and amounts of expenses or revenues recognized for ratemaking purposes, which differences arise in one time period and reverse in one or more other time periods so that the total amounts of expenses or revenues recognized for income tax purposes and for ratemaking purposes are equal.

(3) *Commission-approved ratemaking method* means a ratemaking method approved by the Commission in a final decision including approval of a settlement agreement containing a ratemaking method only if such settlement agreement applies that method beyond the effective term of the settlement agreement.

(4) *Income tax purposes* means for the purpose of computing income tax under the provisions of the Internal Revenue Code or the income tax provisions of the laws of a State or political subdivision of a State (including franchise taxes).

(5) *Income tax component* means that part of the cost of service that covers income tax expenses allowable by the Commission.

(6) *Ratemaking purposes* means for the purpose of fixing, modifying, approving, disapproving or rejecting rates under the Federal Power Act or the Natural Gas Act.

(7) *Tax effect* means the tax reduction or addition associated with a specific expense or revenue transaction.

(8) *Transaction* means an activity or event that gives rise to an accounting entry that is used in determining revenues or expenses.

[46 FR 26636, May 14, 1981. Redesignated and amended by Order 144–A, 47 FR 8342, Feb. 26, 1982; Redesignated by Order 545, 57 FR 53990, Nov. 16, 1992]

§ 35.25 Construction work in progress.

(a) *Applicability.* This section applies to any rate schedule filed under this part by any public utility as defined in subsection 201(e) of the Federal Power Act.

(b) *Definitions.* For purposes of this section:

(1) *Constuction work in progress* or *CWIP* means any expenditure for public utility plant in process of construction that is properly included in Accounts 107 (construction work in progress) and 120.1 (nuclear fuel in process of refinement, conversion, enrichment, and fabrication) of part 101 of this chapter, the

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (Major and Nonmajor), that would otherwise be eligible for allowance for funds used during construction (AFUDC) treatment.

(2) *Double whammy* means a situation which may arise when a wholesale electric rate customer embarks upon its own or participates in a construction program to supply itself with all or a portion of its future power needs, thereby reducing its future dependence on the CWIP of the rate applicant, but is simultaneously forced to pay to the CWIP public utility rate applicant the CWIP portion of the wholesale rates that reflects existing levels of service or a different anticipated service level.

(3) *Fuel conversion facility* means any addition to public utility plant that enables a natural gas-burning plant to convert to the use of other fuels, or that enables an oil-burning plant to convert to the use of other fuels, other than natural gas. Such facilities include those that alter internal plant workings, such as oil or coal burners, soot blowers, bottom ash removal systems and concomitant air pollution control facilities, and any facility needed for receiving and storing the fuel to which the plant is being converted, which facility would not be necessary if the plant continued to burn gas or oil.

(4) *Pollution control facility* means an identifiable structure or portions of a structure that is designed to reduce the amount of pollution produced by the power plant, but does not include any facility that reduces pollution by substituting a different method of generation or that generates the additional power necessitated by the operation of a pollution control facility.

(c) *General rule.* For purposes of any initial rate schedule or any rate schedule change filed under §35.12 or §35.13 of this part, a public utility may include in its rate base any costs of construction work in progress (CWIP), including allowance for funds used during construction (AFUDC), as provided in this section.

(1) *Pollution control facilities*—(i) *General rule.* Any CWIP for pollution control facilities allocable to electric power sales for resale may be included in the rate base of the public utility.

(ii) *Qualification as a pollution control facility.* In determining whether a facility is a pollution control facility for purposes of this section, the Commission will consider:

(A) Whether such facility is the type facility described in the Internal Revenue Service laws, 26 U.S.C. 169(d)(1), as follows:

> ''A new identifiable treatment facility which is used * * * to abate or control water or atmospheric pollution or contamination by removing, altering, disposing, storing, or preventing the creation or emission of pollutants, contaminants, wastes or heat'';

(B) Whether such facility has been certified by a local, state, or federal agency as being in conformity with, or required by, a program of pollution control;

(C) Other evidence showing that such facilities are for pollution control.

(2) *Fuel conversion facilities.* Any CWIP for fuel conversion facilities allocable to electric power sales for resale may be included in the rate base of the public utility.

(3) *Non-pollution control of fuel conversion (non-PC/FC) CWIP.* No more than 50 percent of any CWIP allocable to electric power sales for resale not otherwise included in rate base under paragraphs (c) (1) and (2) of this section, may be included in the rate base of the public utility.

(4) *Forward looking allocation ratios.* Every test period CWIP project requested for wholesale rate base treatment pursuant to §35.26(c)(1), (2), and (3) of this part will be allocated to the customer classes on the basis of forward looking allocation ratios reflecting the anticipated average annual use the wholesale customers will make of the system over the estimated service life of the project. Supporting documentation, as required by §§35.12 and 35.13 of this part, must be in sufficient detail to permit examination and verification of the forward looking allocation ratio's recognition of each wholesale customer's plans, if any, for future alternative or supplementary power supplies. For the purpose of preventing anticompetitive effects, including CWIP-induced price squeeze

and double whammy, sufficient recognition of such plans may require the public utility applicant to provide for separate customer groups or provide for a rate design incorporating selected CWIP project credits.

(d) *Effective date.* If a public utility proposes in its filed rates to include CWIP in rate base under this section, that portion of the rate related to CWIP is collectible at the time the general rates become effective pursuant to Commission order, whether or not subject to refund, except as provided in paragraph (g) of this section.

(e) *Discontinuance of AFUDC.* On the date that any proposed rate that includes CWIP in rate base becomes effective, a public utility that has included CWIP in rate base must discontinue the capitalization of any AFUDC related to those amounts of CWIP is rate base.

(f) *Accounting procedures.* When a public utility files to include CWIP in its rate base pursuant to this section, it must propose accounting procedures in that rate schedule filing that:

(1) Ensure that wholesale customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP proposed to be included in rate base; and

(2) Ensure that wholesale customers will not be charged for any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities.

(g) *Anticompetitive procedures*—(1) *Filing requirements.* In order to facilitate Commission review of the anticompetitive effects of applications for CWIP pursuant to §35.26(c)(3), a public utility applying for rates based upon inclusion of such CWIP in rate base must include the following information in its filing:

(i) The percentage of the proposed increase in the jurisdictional rate level attributable to non-pollution control/fuel conversion CWIP and the percentage of non-pollution control/fuel conversion CWIP supporting the proposed rate level;

(ii) The percentage of non-pollution control/fuel conversion CWIP permitted by the state or local commission supporting the current retail rates of the public utility against which the relevant wholesale customers compete; and

(iii) Individual earned rate of return analyses of each of the competing retail rates developed on a basis fully consistent with the wholesale cost of service for the same test period if the requested percentage of wholesale non-pollution control/fuel conversion CWIP exceeds that permitted by the relevant state or local authority to support the currently competing retail rates.

(2) *Preliminary relief.* (i) If an intervenor in its initial pleading alleges that a price squeeze will occur as a direct result of the public utility's request for CWIP pursuant to §35.26(c)(3), makes a showing that it is likely to incur harm if such CWIP is allowed subject to refund, and makes a showing of how the harm to the intervenor would be mitigated or eliminated by the types of preliminary relief requested, the Commission will consider preliminary relief at the suspension stage of the case pursuant to paragraph (g)(4) of this section. In determining whether to grant preliminary relief, the Commission will balance the following public interest considerations:

(A) The harm to the intervenor if it is not granted preliminary relief from the requested CWIP;

(B) The harm to the public utility if, during the interim period of preliminary relief, the public utility is required to recover its financing charges later through AFUDC rather than immediately through CWIP; and

(C) Mitigating bias against investment in new plants, ensuring accurate price signals, and fostering rate stability.

(ii) Whether or not preliminary relief is granted at the suspension stage will not preclude consideration of further interim or final remedies later in the proceedings, if warranted.

(3) If the Commission makes a final determination that a price squeeze due solely to allowance of a lower percentage of non-pollution control/fuel conversion CWIP in the public utility's retail rate base than allowed by this Commission, the Commission will consider an adjustment to non-pollution control/fuel conversion CWIP in order to eliminate or mitigate the price squeeze.

(4) If an intervenor meets the requirements of paragraph (g)(2) of this section, the Commission, depending on the type of showing made including the likelihood, immediacy, and severity of any anticompetitive harm, may:

(i) Suspend the entire rate increase or all or a portion of the non-pollution control/fuel conversion CWIP component for up to five months;

(ii) Allow all or a portion of the non-pollution control/fuel conversion CWIP only prospectively from the issuance of the Commission's final order on rehearing on the matter; or

(iii) Take such other action as is proper under the circumstances.

[Order 474, 52 FR 23965, June 26, 1987, as amended by Order 474–A, 52 FR 35702, Sept. 23, 1987; Order 474–B, 54 FR 32804, Aug. 10, 1989. Redesignated by Order 545, 57 FR 53990, Nov. 16, 1992, as amended by Order 626, 67 FR 36096, May 23, 2002]

§ 35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) *Purpose*. This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) *Definitions*—1) *Wholesale stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) *Wholesale requirements customer* means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) *Wholesale transmission services* means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce or ordered pursuant to section 211 of the Federal Power Act (FPA).

(4) *Wholesale requirements contract* means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) *Retail stranded cost* means any legitimate, prudent and verifiable cost incurred by a public utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility.

(6) *Retail transmission services* means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) *New wholesale requirements contract* means any *wholesale requirements* contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) *Existing wholesale requirements* contract means any *wholesale requirements* contract executed on or before July 11, 1994.

(c) *Recovery of wholesale stranded costs*—1) *General requirement*. A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205–206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205–206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211–212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, *e.g.*, through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205–206 or section 211–212 rates for wholesale transmission services to that customer.

(2) *Evidentiary demonstration for wholesale stranded cost recovery.* A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1) (v) through (vii) of this section must demonstrate that:

(i) It incurred costs to provide service to a wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of the utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate—Competitive Market Value Estimate) × Length of Obligation (reasonable expectation period).

(3) *Rebuttable presumption.* If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) *Procedure for customer to obtain stranded cost estimate.* A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the

formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) *Recovery of retail stranded costs*—1) *General requirement.* A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) *Evidentiary demonstration necessary for retail stranded cost recovery.* A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred costs to provide service to a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.

[Order 888–A, 62 FR 12460, Mar. 14, 1997]

§ 35.27 Authority of State commissions.

Nothing in this part—

(a) Shall be construed as preempting or affecting any jurisdiction a State commission or other State authority may have under applicable State and Federal law, or

(b) Limits the authority of a State commission in accordance with State and Federal law to establish

(1) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(2) Non-discriminatory fees for the distribution of such electric energy to

retail consumers for purposes established in accordance with State law.

[Order 697, 72 FR 40038, July 20, 2007]

§ 35.28 Non-discriminatory open access transmission tariff.

(a) *Applicability*. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) *Definitions*—(1) *Requirements service agreement* means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) *Economy energy coordination agreement* means a contract, or service schedule thereunder, that provides for trading of electric energy on an ''if, as and when available'' basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) *Non-economy energy coordination agreement* means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(4) *Demand response* means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.

(5) *Demand response resource* means a resource capable of providing demand response.

(6) *An operating reserve shortage* means a period when the amount of available supply falls short of demand plus the operating reserve requirement.

(7) *Market Monitoring Unit* means the person or entity responsible for carrying out the market monitoring functions that the Commission has ordered Commission-approved independent system operators and regional transmission organizations to perform.

(8) *Market Violation* means a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

(9) *Electric storage resource* as used in this section means a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.

(c) *Non-discriminatory open access transmission tariffs*. (1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff, which tariff must be the *pro forma* tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service

over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(iv) Any public utility whose transmission facilities are under the independent control of a Commission-approved ISO or RTO may satisfy its obligation under paragraph (c)(1) of this section, with respect to such facilities, through the open access transmission tariff filed by the ISO or RTO.

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the *pro forma* tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(vii) Each public utility's open access transmission tariff must include the standards incorporated by reference in part 38 of this chapter.

(2) Subject to the exceptions in paragraphs (c)(2)(i) and (c)(3)(iii) of this section, every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access transmission tariff filed pursuant to this section.

(i) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(ii) [Reserved]

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after October 11, 2011, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in

accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(iii) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must take transmission service under a joint pool-wide or system-wide open access transmission tariff filed pursuant to this section for wholesale trades among the pool or system members.

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the *pro forma* tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(d) *Waivers.* (1) A public utility subject to the requirements of this section and 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) may file a request for waiver of all or part of such requirements for good cause shown. Except as provided in paragraph (f) of this section, an application for waiver must be filed no later than 60 days prior to the time the public utility would have to comply with the requirement.

(2) The requirements of this section, 18 CFR parts 37 (Open Access Same-Time Information System) and 358 (Standards of Conduct for Transmission Providers) are waived for any public utility that is or becomes subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities, in whole or in part, as that term is defined in the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, or comparable jurisdictional interconnection facilities that are the subject of interconnection agreements other than the standard generator interconnection procedures and agreements referenced in paragraph (f) of this section, if the entity that owns, operates, or controls such facilities either sells electric energy, or files a statement with the Commission that it commits to comply with and be bound by the obligations and procedures applicable to electric utilities under section 210 of the Federal Power Act.

(i) The waivers referenced in this paragraph (d)(2) shall be deemed to be revoked as of the date the public utility ceases to satisfy the qualifications of this paragraph (d)(2), and may be revoked by the Commission if the Commission determines that it is in the public interest to do so. After revocation of its waivers, the public utility must comply with the requirements that had been waived within 60 days of revocation.

(ii) Any eligible entity that seeks interconnection or transmission services with respect to the interconnection facilities for which a waiver is in effect pursuant to this paragraph (d)(2) may follow the procedures in sections 210, 211, and 212 of the Federal Power Act, 18 CFR 2.20, and 18 CFR part 36. In

any proceeding pursuant to this paragraph (d)(2)(ii):

(A) The Commission will consider it to be in the public interest to grant priority rights to the owner and/or operator of interconnection facilities specified in this paragraph (d)(2) to use capacity thereon when such owner and/or operator can demonstrate that it has specific plans with milestones to use such capacity to interconnect its or its affiliate's future generation projects.

(B) For the first five years after the commercial operation date of the interconnection facilities specified in this paragraph (d)(2), the Commission will apply the rebuttable presumption that the owner and/or operator of such facilities has definitive plans to use the capacity thereon, and it is thus in the public interest to grant priority rights to the owner and/or operator of such facilities to use capacity thereon.

(e) *Non-public utility procedures for tariff reciprocity compliance.* (1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) *Standard generator interconnection procedures and agreements.* (1) Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

(ii)–(iv) [Reserved]

(2) The non-public utility procedures for tariff reciprocity compliance described in paragraph (e) of this section are applicable to the standard interconnection procedures and agreements.

(3) A public utility subject to the requirements of this paragraph (f) may file a request for waiver of all or part of the requirements of this paragraph (f), for good cause shown.

(g) *Tariffs and operations of Commission-approved independent system operators and regional transmission organizations*—(1) *Demand response and pricing*—(i) *Ancillary services provided by demand response resources.* (A) Every Commission-approved independent system operator or regional transmission organization that operates organized markets based on competitive bidding for energy imbalance, spinning reserves,supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services (or its functional equivalent in the Commission-approved independent

system operator's or regional transmission organization's tariff) must accept bids from demand response resources in these markets for that product on a basis comparable to any other resources, if the demand response resource meets the necessary technical requirements under the tariff, and submits a bid under the Commission-approved independent system operator's or regional transmission organization's bidding rules at or below the market-clearing price, unless not permitted by the laws or regulations of the relevant electric retail regulatory authority.

(B) Each Commission-approved independent system operator or regional transmission organization must allow providers of a demand response resource to specify the following in their bids:

(*1*) A maximum duration in hours that the demand response resource may be dispatched;

(*2*) A maximum number of times that the demand response resource may be dispatched during a day; and

(*3*) A maximum amount of electric energy reduction that the demand response resource may be required to provide either daily or weekly.

(ii) *Removal of deviation charges.* A Commission-approved independent system operator or regional transmission organization with a tariff that contains a day-ahead and a real-time market may not assess charge to a purchaser of electric energy in its day-ahead market for purchasing less power in the real-time market during a real-time market period for which the Commission-approved independent system operator or regional transmission organization declares an operating reserve shortage or makes a generic request to reduce load to avoid an operating reserve shortage.

(iii) *Aggregation of retail customers.* Each Commission-approved independent system operator and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers. An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers.

(iv) *Price formation during periods of operating reserve shortage.* (A) Each Commission-approved independent system operator and regional transmission organization must modify its market rules to allow the market-clearing price during periods of operating reserve shortage to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power. Each Commission-approved independent system operator and regional transmission organization must trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval.

(B) A Commission-approved independent system operator or regional transmission organization may phase in this modification of its market rules.

(v) *Demand response compensation in energy markets.* Each Commission-approved independent system operator or regional transmission organization that has a tariff provision permitting demand response resources to participate as a resource in the energy market by reducing consumption of electric energy from their expected levels in response to price signals must:

(A) Pay to those demand response resources the market price for energy for these reductions when these demand response resources have the capability to balance supply and demand and when payment of the market price for energy to these resources is cost-effective as determined by a net benefits test accepted by the Commission;

(B) Allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.

(vi) *Settlement intervals.* Each Commission-approved independent system operator and regional transmission organization must settle energy transactions in its real-time markets at the same time interval it dispatches energy, must settle operating reserves transactions in its real-time markets at the same time interval it prices operating reserves, and must settle intertie transactions at the same time interval it schedules intertie transactions.

(2) *Long-term power contracting in organized markets.* Each Commission-approved independent system operator or regional transmission organization must provide a portion of its Web site for market participants to post offers to buy or sell power on a long-term basis.

(3) *Market monitoring policies.* (i) Each Commission-approved independent system operator or regional transmission organization must modify its tariff provisions governing its Market Monitoring Unit to reflect the directives provided in OrderNo. 719, including the following:

(A) Each Commission-approved independent system operator or regional transmission organization must include in its tariff a provision to provide its Market Monitoring Unit access to Commission-approved independent system operator and regional transmission organization market data, resources and personnel to enable the MarketMonitoring Unit to carry out its functions.

(B) The tariff provision must provide the Market Monitoring Unit complete access to the Commission-approved independent system operator's and regional transmission organization's databases of market information.

(C) The tariff provision must provide that any data created by the Market Monitoring Unit, including, but not limited to, reconfiguring of the Commission-approved independent system operator's and regional transmission organization's data, will be kept within the exclusive control of the Market Monitoring Unit.

(D) The Market Monitoring Unit must report to the Commission-approved independent system operator's or regional transmission organization's board of directors, with its management members removed, or to an independent committee of the Commission-approved independent system operator's or regional transmission organization's board of directors. A Commission-approved independent system operator or regional transmission organization that has both an internal Market Monitoring Unit and an external Market Monitoring Unit may permit the internal Market Monitoring Unit to report to management and the external Market Monitoring Unit to report to the Commission-approved independent system operator's or regional transmission organization's board of directors with its management members removed, or to an independent committee of the Commission-approved independent system operator or regional transmission organization board of directors. If the internal market monitor is responsible for carrying out any or all of the core Market Monitoring Unit functions identified in paragraph (g)(3)(ii) of this section, the internal market monitor must report to the independent system operator's or regional transmission organization's board of directors.

(E) A Commission-approved independent system operator or regional transmission organization may not alter the reports generated by the Market Monitoring Unit, or dictate the conclusions reached by the Market Monitoring Unit.

(F) Each Commission-approved independent system operator or regional transmission organization must consolidate the core Market Monitoring

Unit provisions into one section of its tariff. Each independent system operator or regional transmission organization must include a mission statement in the introduction to the Market Monitoring Unit provisions that identifies the Market Monitoring Unit's goals, including the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses.

(ii) *Core Functions of Market Monitoring Unit.* The Market Monitoring Unit must perform the following core functions:

(A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-approved independent system operator or regional transmission organization, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants, provided that:

(*1*) The Market Monitoring Unit is not to effectuate its proposed market design itself, and

(*2*) The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to Commission staff in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) Review and report on the performance of the wholesale markets to the Commission-approved independent system operator or regional transmission organization, the Commission, and other interested entities such as state commissions and market participants, on at least a quarterly basis and submit a more comprehensive annual state of the market report. The Market Monitoring Unit may issue additional reports as necessary.

(C) Identify and notify the Commission's Office of Enforcement staff of instances in which a market participant's or the Commission-approved independent system operator's or regional transmission organization's behavior may require investigation, including, but not limited to, suspected Market Violations.

(iii) *Tariff administration and mitigation* (A) A Commission-approved independent system operator or regional transmission organization may not permit its Market Monitoring Unit, whether internal or external, to participate in the administration of the Commission-approved independent system operator's or regional transmission organization's tariff or, except as provided in paragraph (g)(3)(iii)(D) of this section, to conduct prospective mitigation.

(B) A Commission-approved independent system operator or regional transmission organization may permit its Market Monitoring Unit to provide the inputs required for the Commission-approved independent system operator or regional transmission organization to conduct prospective mitigation, including, but not limited to, reference levels, identification of system constraints, and cost calculations.

(C) A Commission-approved independent system operator or regional transmission organization may allow its Market Monitoring Unit to conduct retrospective mitigation.

(D) A Commission-approved independent system operator or regional transmission organization with a hybrid Market Monitoring Unit structure may permit its internal market monitor to conduct prospective and/or retrospective mitigation, in which case it must assign to its external market monitor the responsibility and the tools to monitor the quality and appropriateness of the mitigation.

(E) Each Commission-approved independent system operator or regional transmission organization must identify in its tariff the functions the Market Monitoring Unit will perform and the functions the Commission-approved independent system operator or regional transmission organization will perform.

(iv) *Protocols on Market Monitoring Unit referrals to the Commission of suspected violations.* (A) A Market Monitoring Unit is to make a non-public referral to the Commission in all instances where the Market Monitoring Unit has reason to believe that a Market Violation has occurred. While the

Market Monitoring Unit need not be able to prove that a Market Violation has occurred, the Market Monitoring Unit is to provide sufficient credible information to warrant further investigation by the Commission. Once the Market Monitoring Unit has obtained sufficient credible information to warrant referral to the Commission, the Market Monitoring Unit is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Market Monitoring Unit from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Market Monitoring Unit is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(*1*) The name[s] of and, if possible, the contact information for, the entity[ies] that allegedly took the action[s] that constituted the alleged Market Violation[s];

(*2*) The date[s] or time period during which the alleged Market Violation[s] occurred and whether the alleged wrongful conduct is ongoing;

(*3*) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(*4*) The specific act[s] or conduct that allegedly constituted the Market Violation;

(*5*) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(*6*) If the Market Monitoring Unit believes that the act[s] or conduct constituted a violation of the anti-manipulation rule of Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(*7*) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any information that the Market Monitoring Unit learns of that may be related to the referral, but the Market Monitoring Unit is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission Staff.

(v) *Protocols on Market Monitoring Unit Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.* (A) A Market Monitoring Unit is to make a referral to the Commission in all instances where the Market Monitoring Unit has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Market Monitoring Unit must limit distribution of its identifications and recommendations to the independent system operator or regional transmission organization and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Market Monitoring Unit may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(*1*) A detailed narrative describing the perceived market design flaw[s];

(*2*) The consequences of the perceived market design flaw[s], including, if known, an estimate of economic impact on the market;

(*3*) The rule or tariff change(s) that the Market Monitoring Unit believes could remedy the perceived market design flaw;

(*4*) Any other information the Market Monitoring Unit believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Market Monitoring Unit is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Market Monitoring Unit to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

(vi) *Market Monitoring Unit ethics standards*. Each Commission-approved independent system operator or regional transmission organization must include in its tariff ethical standards for its Market Monitoring Unit and the employees of its Market Monitoring Unit. At a minimum, the ethics standards must include the following requirements:

(A) The Market Monitoring Unit and its employees must have no material affiliation with any market participant or affiliate.

(B) The Market Monitoring Unit and its employees must not serve as an officer, employee, or partner of a market participant.

(C) The Market Monitoring Unit and its employees must have no material financial interest in any market participant or affiliate with potential exceptions for mutual funds and non-directed investments.

(D) The Market Monitoring Unit and its employees must not engage in any market transactions other than the performance of their duties under the tariff.

(E) The Market Monitoring Unit and its employees must not be compensated, other than by the Commission-approved independent system operator or regional transmission organization that retains or employs it, for any expert witness testimony or other commercial services, either to the Commission-approved independent system operator or regional transmission organization or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the Commission-approved independent system operator or regional transmission organization or to the Commission-approved independent system operator's or regional transmission organization's markets.

(F) The Market Monitoring Unit and its employees may not accept anything of value from a market participant in excess of a *de minimis* amount.

(G) The Market Monitoring Unit and its employees must advise a supervisor in the event they seek employment with a market participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the market participant.

(4) *Electronic delivery of data*. Each Commission-approved regional transmission organization and independent system operator must electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the Commission, data related to the markets that the regional transmission organization or independent system operator administers.

(5) *Offer and bid data*. (i) Unless a Commission-approved independent system operator or regional transmission organization obtains Commission approval for a different period, each Commission-approved independent system operator and regional transmission organization must release its offer and bid data within three months.

(ii) A Commission-approved independent system operator or regional transmission organization must mask the identity of market participants when releasing offer and bid data. The Commission-approved independent system operators and regional transmission organization may propose a time period for eventual unmasking.

(6) *Responsiveness of Commission-approved independent system operators and regional transmission organizations.* Each Commission-approved independent system operator or regional transmission organization must adopt business practices and procedures that achieve Commission-approved independent system operator and regional transmission organization board of directors' responsiveness to customers and other stakeholders and satisfy the following criteria:

(i) *Inclusiveness.* The business practices and procedures must ensure that any customer or other stakeholder affected by the operation of the Commission-approved independent system operator or regional transmission organization, or its representative, is permitted to communicate the customer's or other stakeholder's views to the independent system operator's or regional transmission organization's board of directors;

(ii) *Fairness in balancing diverse interests.* The business practices and procedures must ensure that the interests of customers or other stakeholders are equitably considered, and that deliberation and consideration of Commission-approved independent system operator's and regional transmission organization's issues are not dominated by any single stakeholder category;

(iii) *Representation of minority positions.* The business practices and procedures must ensure that, in instances where stakeholders are not in total agreement on a particular issue, minority positions are communicated to the Commission-approved independent system operator's and regional transmission organization's board of directors at the same time as majority positions; and

(iv) *Ongoing responsiveness.* The business practices and procedures must provide for stakeholder input into the Commission-approved independent system operator's or regional transmission organization's decisions as well as mechanisms to provide feedback to stakeholders to ensure that information exchange and communication continue over time.

(7) *Compliance filings.* All Commission-approved independent system operators and regional transmission organizations must make a compliance filing with the Commission as described in Order No. 719 under the following schedule:

(i) The compliance filing addressing the accepting of bids from demand response resources in markets for ancillary services on a basis comparable to other resources, removal of deviation charges, aggregation of retail customers, shortage pricing during periods of operating reserve shortage, long-term power contracting in organized markets, Market Monitoring Units, Commission-approved independent system operators' and regional transmission organizations' board of directors' responsiveness, and reporting on the study of the need for further reforms to remove barriers to comparable treatment of demand response resources must be submitted on or before April 28, 2009.

(ii) A public utility that is approved as a regional transmission organization under § 35.34, or that is not approved but begins to operate regional markets for electric energy or ancillary services after December 29, 2008, must comply with Order No. 719 and the provisions of paragraphs (g)(1) through (g)(5) of this section before beginning operations.

(8) *Frequency regulation compensation in ancillary services markets.* Each Commission-approved independent system operator or regional transmission organization that has a tariff that provides for the compensation for frequency regulation service must provide such compensation based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

(9) *Electric storage resources.* (i) Each Commission-approved independent system operator and regional transmission organization must have tariff provisions providing a participation model for electric storage resources that:

(A) Ensures that a resource using the participation model for electric storage resources in an independent system operator or regional transmission organization market is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing;

(B) Ensures that a resource using the participation model for electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with rules that govern the conditions under which a resource can set the wholesale price;

(C) Accounts for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and

(D) Establishes a minimum size requirement for resources using the participation model for electric storage resources that does not exceed 100 kW.

(ii) The sale of electric energy from an independent system operator or regional transmission organization market to an electric storage resource that the resource then resells back to that market must be at the wholesale locational marginal price.

(10) *Transparency*—(i) *Uplift reporting.* Each Commission-approved independent system operator or regional transmission organization must post two reports, at minimum, regarding uplift on a publicly accessible portion of its website. First, each Commission-approved independent system operator or regional transmission organization must post uplift, paid in dollars, and categorized by transmission zone, day, and uplift category. Transmission zone shall be defined as the geographic area that is used for the local allocation of charges. Transmission zones with fewer than four resources may be aggregated with one or more neighboring transmission zones, until each aggregated zone contains at least four resources, and reported collectively. This report shall be posted within 20 calendar days of the end of each month. Second, each Commission-approved independent system operator or regional transmission organization must post the resource name and the total amount of uplift paid in dollars aggregated across the month to each resource that received uplift payments within the calendar month. This report shall be posted within 90 calendar days of the end of each month.

(ii) *Reporting Operator-Initiated Commitments.* Each Commission-approved independent system operator or regional transmission organization must post a report of each operator-initiated commitment listing the size of the commitment, transmission zone, commitment reason, and commitment start time on a publicly accessible portion of its website within 30 calendar days of the end of each month. Transmission zone shall be defined as a geographic area that is used for the local allocation of charges. Commitment reasons shall include, but are not limited to, system-wide capacity, constraint management, and voltage support.

(iii) *Transmission constraint penalty factors.* Each Commission-approved independent system operator or regional transmission organization must include, in its tariff, its transmission constraint penalty factor values; the circumstances, if any, under which the transmission constraint penalty factors can set locational marginal prices; and the procedure, if any, for temporarily changing the transmission constraint penalty factor values. Any procedure for temporarily changing transmission constraint penalty factor values must provide for notice of the change to market participants.

(11) A resource's incremental energy offer must be capped at the higher of $1,000/MWh or that resource's cost-based incremental energy offer. For the purpose of calculating Locational Marginal Prices, Regional Transmission Organizations and Independent System Operators must cap cost-based incremental energy offers at $2,000/MWh. The actual or expected costs underlying a resource's cost-based incremental energy offer above $1,000/MWh must be verified before that offer can

be used for purposes of calculating Locational Marginal Prices. If a resource submits an incremental energy offer above $1,000/MWh and the actual or expected costs underlying that offer cannot be verified before the market clearing process begins, that offer may not be used to calculate Locational Marginal Prices and the resource would be eligible for a make-whole payment if that resource is dispatched and the resource's actual costs are verified after-the-fact. A resource would also be eligible for a make-whole payment if it is dispatched and its verified cost-based incremental energy offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh.

[Order 888, 61 FR 21693, May 10, 1996]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 35.28, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov*.

§ 35.29 Treatment of special assessments levied under the Atomic Energy Act of 1954, as amended by Title XI of the Energy Policy Act of 1992.

The costs that public utilities incur relating to special assessments under the Atomic Energy Act of 1954, as amended by the Energy Policy Act of 1992, are costs that may be reflected in jurisdictional rates. Public utilities seeking to recover the costs incurred relating to special assessments shall comply with the following procedures.

(a) *Fuel adjustment clauses.* In computing the Account 518 cost of nuclear fuel pursuant to § 35.14(a)(6), utilities seeking to recover the costs of special assessments through their fuel adjustment clauses shall:

(1) Deduct any expenses associated with special assessments included in Account 518;

(2) Add to Account 518 one-twelfth of any payments made for special assessments within the 12-month period ending with the current month; and

(3) Deduct from Account 518 one-twelfth of any refunds of payments made for special assessments received within the 12-month period ending with the current month that is received from the Federal government because the public utility has contested a special assessment or overpaid a special assessment.

(b) *Cost of service data requirements.* Public utilities filing rate applications under §§ 35.12 or 35.13 (regardless of whether the utility elects the abbreviated, unadjusted Period I, adjusted Period I, or Period II cost support requirements) must submit cost data that is computed in accordance with the requirements specified in paragraphs (a) (1), (2) and (3) of this section.

(c) *Formula rates.* Public utilities with formula rates on file that provide for the automatic recovery of nuclear fuel costs must reflect the costs of special assessments in accordance with the requirements specified in paragraphs (a) (1), (2) and (3) of this section.

[Order 557, 58 FR 51221, Oct. 1, 1993. Redesignated by Order 888, 61 FR 21692, May 10, 1996]

Subpart D—Procedures and Requirements for Public Utility Sales of Power to Bonneville Power Administration Under Northwest Power Act

AUTHORITY: Federal Power Act, 16 U.S.C. 792–828c (1976 and Supp. IV 1980) and Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 830–839h (Supp. IV (1980)).

§ 35.30 General provisions.

(a) *Applicability.* This subpart applies to any sales of electric power subject to the Commission's jurisdiction under Part II of the Federal Power Act from public utilities to the Administrator of the Bonneville Power Administration (BPA) at the average system cost (ASC) of that utility's resources (electric power generation by the utility) pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. 830–839h. The ASC is determined by BPA in accordance with 18 CFR part 301.

(b) *Effectiveness of rates.* (1) During the period between the date of BPA's determination of ASC and the date of the final order issued by the Commission, the utility may charge the rate based on the ASC determined by BPA, subject to § 35.31(c) of this part.

(2) Except as otherwise provided under this section, the ASC ordered by the Commission will be deemed in effect from the beginning of the relevant exchange period, as defined in §301.1(b)(95) of this chapter. For any initial exchange period after the Commission approves a new ASC methodology, the ASC will be effective retroactively under this paragraph only if the utility files its new ASC within the time allowed under BPA procedures. Any utility that files a revised ASC with BPA in accordance with this paragraph must promptly file with the Commission a notice of timely filing of the new ASC.

(c) *Filing requirements.* Within 15 business days of the date of issuance of the BPA report on a utility's ASC, the utility must file with the Commission the ASC determined by BPA, the BPA written report, the utility's ASC schedules, material necessary to comply with 18 CFR 35.13(c), and any other material requested by the Commission or its staff.

[Order 337, 48 FR 46976, Oct. 17, 1983, as amended by Order 400, 49 FR 39300, Oct. 5, 1984]

§35.31 Commission review.

(a) *Procedures.* Filings under this subpart are subject to the procedures applicable to other filings under section 205 of the Federal Power Act, as the Commission deems appropriate.

(b) *Commission standard.* With respect to any filing under this subpart, the Commission will determine whether the ASC set by BPA for the applicable exchange period was determined in accordance with the ASC methodology set forth at 18 CFR 301.1. If the ASC is not in accord with the methodology, the Commission will order that BPA amend the ASC to conform with the methodology. If the ASC is in accord with the methodology, the rate is deemed just and reasonable.

(c) *Refunds and adjustments.* (1) Any ASC-based rate charged by a public utility under this subpart pending Commission order is subject to refund or to adjustment that increases the ASC-based rate.

(2) Any interest on refunds ordered by the Commission under this subpart is computed in accordance with 18 CFR 35.19a. Interest on any increase ordered by the Commission will be at the rate charged to BPA by the U.S. Treasury during that period, unless the Commission orders another interest rate.

(Approved by the Office of Management and Budget under control number 1902–0096)

[Order 337, 48 FR 46976, Oct. 17, 1983, as amended at 49 FR 1177, Jan. 10, 1984]

Subpart E—Regulations Governing Nuclear Plant Decommissioning Trust Funds

§35.32 General provisions.

(a) If a public utility has elected to provide for the decommissioning of a nuclear power plant through a nuclear plant decommissioning trust fund (Fund), the Fund must meet the following criteria:

(1) The Fund must be an external trust fund in the United States, established pursuant to a written trust agreement, that is independent of the utility, its subsidiaries, affiliates or associates. If the trust fund includes monies collected both in Commission-jurisdictional rates and in non-Commission-jurisdictional rates, then a separate account of the Commission-jurisdictional monies shall be maintained.

(2) The utility may provide overall investment policy to the Trustee or Investment Manager, but it may do so only in writing, and neither the utility nor its subsidiaries, affiliates or associates may serve as Investment Manager or otherwise engage in day-to-day management of the Fund or mandate individual investment decisions.

(3) The Fund's Investment Manager must exercise the standard of care, whether in investing or otherwise, that a prudent investor would use in the same circumstances. The term ''prudent investor'' means a prudent investor as described in Restatement of the Law (Third), Trusts §227, including general comments and reporter's notes, pages 8–101. St. Paul, MN: American Law Institute Publishers, (1992). ISBN 0–314–84246–2. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

Copies may be obtained from the American Law Institute, 4025 Chestnut Street, Philadelphia, PA 19104, and are also available in local law libraries. Copies may be inspected at the Federal Energy Regulatory Commission's Library, Room 95–01, 888 First Street, NE. Washington, DC or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal__register/code__of__federal__regulations/ibr__locations.html*.

(4) The Trustee shall have a net worth of at least $100 million. In calculating the $100 million net worth requirement, the net worth of the Trustee's parent corporation and/or affiliates may be taken into account only if such entities guarantee the Trustee's responsibilities to the Fund.

(5) The Trustee or Investment Manager shall keep accurate and detailed accounts of all investments, receipts, disbursements and transactions of the Fund. All accounts, books and records relating to the Fund shall be open to inspection and audit at reasonable times by the utility or its designee or by the Commission or its designee. The utility or its designee must notify the Commission prior to performing any such inspection or audit. The Commission may direct the utility to conduct an audit or inspection.

(6) Absent the express authorization of the Commission, no part of the assets of the Fund may be used for, or diverted to, any purpose other than to fund the costs of decommissioning the nuclear power plant to which the Fund relates, and to pay administrative costs and other incidental expenses, including taxes, of the Fund.

(7) If the Fund balances exceed the amount actually expended for decommissioning after decommissioning has been completed, the utility shall return the excess jurisdictional amount to ratepayers, in a manner the Commission determines.

(8) Except for investments tied to market indexes or other mutual funds, the Investment Manager shall not invest in any securities of the utility for which it manages the funds or in that utility's subsidiaries, affiliates, or associates or their successors or assigns.

(9) The utility and the Fiduciary shall seek to obtain the best possible tax treatment of amounts collected for nuclear plant decommissioning. In this regard, the utility and the Fiduciary shall take maximum advantage of tax deductions and credits, when it is consistent with sound business practices to do so.

(10) Each utility shall deposit in the Fund at least quarterly all amounts included in Commission-jurisdictional rates to fund nuclear power plant decommissioning.

(b) The establishment, organization, and maintenance of the Fund shall not relieve the utility or its subsidiaries, affiliates or associates of any obligations it may have as to the decommissioning of the nuclear power plant. It is not the responsibility of the Fiduciary to ensure that the amount of monies that a Fund contains are adequate to pay for a nuclear unit's decommissioning.

(c) A utility may establish both qualified and non-qualified Funds with respect to a utility's interest in a specific nuclear plant. This section applies to both ''qualified'' (under the Internal Revenue Code, 26 U.S.C. 468A, or any successor section) and non-qualified Funds.

(d) A utility must regularly supply to the Fund's Investment Manager, and regularly update, essential information about the nuclear unit covered by the Trust Fund Agreement, including its description, location, expected remaining useful life, the decommissioning plan the utility proposes to follow, the utility's liquidity needs once decommissioning begins, and any other information that the Fund's Investment Manager would need to construct and maintain, over time, a sound investment plan.

(e) A utility should monitor the performance of all Fiduciaries of the Fund and, if necessary, replace them if they are not properly performing assigned responsibilities.

[Order 580–A, 62 FR 33348, June 19, 1997, as amended at 69 FR 18803, Apr. 9, 2004]

§ 35.33 Specific provisions.

(a) In addition to the general provisions of § 35.32, the Trustee must observe the provisions of this section.

(b) The Trustee may use Fund assets only to:

(1) Satisfy the liability of a utility for decommissioning costs of the nuclear power plant to which the Fund relates as provided by § 35.32; and

(2) Pay administrative costs and other incidental expenses, including taxes, of the Fund as provided by § 35.32.

(c) To the extent that the Trustee does not currently require the assets of the Fund for the purposes described in paragraphs (b)(1) and (b)(2) of this section, the Investment Manager, when investing Fund assets, must exercise the same standard of care that a reasonable person would exercise in the same circumstances. In this context, a ''reasonable person'' means a prudent investor as described in Restatement of the Law (Third), Trusts § 227, including general comments and reporter's notes, pages 8–101. St. Paul, MN: American Law Institute Publishers, 1992. ISBN 0–314–84246–2. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from the American Law Institute, 4025 Chestnut Street, Philadelphia, PA 19104, and are also available in local law libraries. Copies may be inspected at the Federal Energy Regulatory Commission, 888 First Street, NE. Washington, DC or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html*.

(d) The utility must submit to the Commission by March 31 of each year, one original and three conformed copies of the financial report furnished to the utility by the Fund's Trustee that shows for the previous calendar year:

(1) Fund assets and liabilities at the beginning of the period;

(2) Activity of the Fund during the period, including amounts received from the utility, a summary amount for purchases of fund investments and a summary amount for sales of fund investments, gains and losses from investment activity, disbursements from the Fund for decommissioning activity and payment of Fund expenses, including taxes; and

(3) Fund assets and liabilities at the end of the period. The report should not include the liability for decommissioning.

(4) Public utilities owning nuclear plants must maintain records of individual purchase and sales transactions until after decommissioning has been completed and any excess jurisdictional amounts have been returned to ratepayers in a manner that the Commission determines. The public utility need not include these records in the financial report that it furnishes to the Commission by March 31 of each year.

(e) The utility must also mail a copy of the financial report provided to the Commission pursuant to paragraph (d) of this section to anyone who requests it.

(f) If an independent public accountant has expressed an opinion on the report or on any portion of the report, then that opinion must accompany the report.

[Order 580–A, 62 FR 33348, June 19, 1997, as amended at 69 FR 18803, Apr. 9, 2004; Order 658, 70 FR 34343, June 14, 2005; Order 737, 75 FR 43404, July 26, 2010]

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 Regional Transmission Organizations.

(a) *Purpose.* This section establishes required characteristics and functions for Regional Transmission Organizations for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring non-discrimination in the provision of electric transmission services. This section further directs each public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to make certain filings with respect to forming and participating in a Regional Transmission Organization.

(b) *Definitions.* (1) *Regional Transmission Organization* means an entity that satisfies the minimum characteristics set forth in paragraph (j) of this section, performs the functions set forth in paragraph (k) of this section, and accommodates the open architecture condition set forth in paragraph (l) of this section.

(2) *Market participant* means:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the Regional Transmission Organization, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Regional Transmission Organization's actions or decisions.

(3) *Affiliate* means the definition given in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)).

(4) *Class of market participants* means two or more market participants with common economic or commercial interests.

(c) *General rule.* Except for those public utilities subject to the requirements of paragraph (h) of this section, every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000 must file with the Commission, no later than October 15, 2000, one of the following:

(1) A proposal to participate in a Regional Transmission Organization consisting of one of the types of submittals set forth in paragraph (d) of this section; or

(2) An alternative filing consistent with paragraph (g) of this section.

(d) *Proposal to participate in a Regional Transmission Organization.* For purposes of this section, a proposal to participate in a Regional Transmission Organization means:

(1) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to create a new Regional Transmission Organization;

(2) Such filings, made individually or jointly with other entities, pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as are necessary to join a Regional Transmission Organization approved by the Commission on or before the date of the filing; or

(3) A petition for declaratory order, filed individually or jointly with other entities, asking whether a proposed transmission entity would qualify as a Regional Transmission Organization and containing at least the following:

(i) A detailed description of the proposed transmission entity, including a description of the organizational and operational structure and the intended participants;

(ii) A discussion of how the transmission entity would satisfy each of the characteristics and functions of a Regional Transmission Organization specified in paragraphs (j), (k) and (l) of this section;

(iii) A detailed description of the Federal Power Act section 205 rates that will be filed for the Regional Transmission Organization; and

(iv) A commitment to make filings pursuant to sections 203, 205 and 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824e), as necessary, promptly after the Commission issues an order in response to the petition.

(4) Any proposal filed under this paragraph (d) must include an explanation of efforts made to include public power entities and electric power cooperatives in the proposed Regional Transmission Organization.

(e) [Reserved]

(f) *Transfer of operational control.* Any public utility's proposal to participate in a Regional Transmission Organization filed pursuant to paragraph (c)(1) of this section must propose that operational control of that public utility's transmission facilities will be transferred to the Regional Transmission Organization on a schedule that will allow the Regional Transmission Organization to commence operating the facilities no later than December 15, 2001.

NOTE TO PARAGRAPH (f): The requirement in paragraph (f) of this section may be satisfied

by proposing to transfer to the Regional Transmission Organization ownership of the facilities in addition to operational control.

(g) *Alternative filing.* Any filing made pursuant to paragraph (c)(2) of this section must contain:

(1) A description of any efforts made by that public utility to participate in a Regional Transmission Organization;

(2) A detailed explanation of the economic, operational, commercial, regulatory, or other reasons the public utility has not made a filing to participate in a Regional Transmission Organization, including identification of any existing obstacles to participation in a Regional Transmission Organization; and

(3) The specific plans, if any, the public utility has for further work toward participation in a Regional Transmission Organization, a proposed timetable for such activity, an explanation of efforts made to include public power entities in the proposed Regional Transmission Organization, and any factors (including any law, rule or regulation) that may affect the public utility's ability or decision to participate in a Regional Transmission Organization.

(h) *Public utilities participating in approved transmission entities.* Every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, and that has filed with the Commission on or before March 6, 2000 to transfer operational control of its facilities to a transmission entity that has been approved or conditionally approved by the Commission on or before March 6, 2000 as being in conformance with the eleven ISO principles set forth in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶31,036 (Final Rule on Open Access and Stranded Costs; see 61 FR 21540, May 10, 1996), must, individually or jointly with other entities, file with the Commission, no later than January 15, 2001:

(1) A statement that it is participating in a transmission entity that has been so approved;

(2) A detailed explanation of the extent to which the transmission entity in which it participates has the characteristics and performs the functions of a Regional Transmission Organization specified in paragraphs (j) and (k) of this section and accommodates the open architecture conditions in paragraph (l) of this section; and

(3) To the extent the transmission entity in which the public utility participates does not meet all the requirements of a Regional Transmission Organization specified in paragraphs (j), (k), and (l) of this section,

(i) A proposal to participate in a Regional Transmission Organization that meets such requirements in accordance with paragraph (d) of this section,

(ii) A proposal to modify the existing transmission entity so that it conforms to the requirements of a Regional Transmission Organization, or

(iii) A filing containing the information specified in paragraph (g) of this section addressing any efforts, obstacles, and plans with respect to conformance with those requirements.

(i) *Entities that become public utilities with transmission facilities.* An entity that is not a public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of March 6, 2000, but later becomes such a public utility, must file a proposal to participate in a Regional Transmission Organization in accordance with paragraph (d) of this section, or an alternative filing in accordance with paragraph (g) of this section, by October 15, 2000 or 60 days prior to the date on which the public utility engages in any transmission of electric energy in interstate commerce, whichever comes later. If a proposal to participate in accordance with paragraph (d) of this section is filed, it must propose that operational control of the applicant's transmission system will be transferred to the Regional Transmission Organization within six months of filing the proposal.

(j) *Required characteristics for a Regional Transmission Organization.* A Regional Transmission Organization must satisfy the following characteristics when it commences operation:

(1) *Independence.* The Regional Transmission Organization must be independent of any market participant.

The Regional Transmission Organization must include, as part of its demonstration of independence, a demonstration that it meets the following:

(i) The Regional Transmission Organization, its employees, and any non-stakeholder directors must not have financial interests in any market participant.

(ii) The Regional Transmission Organization must have a decision making process that is independent of control by any market participant or class of participants.

(iii) The Regional Transmission Organization must have exclusive and independent authority under section 205 of the Federal Power Act (16 U.S.C. 824d), to propose rates, terms and conditions of transmission service provided over the facilities it operates.

NOTE TO PARAGRAPH (j)(1)(iii): Transmission owners retain authority under section 205 of the Federal Power Act (16 U.S.C. 824d) to seek recovery from the Regional Transmission Organization of the revenue requirements associated with the transmission facilities that they own.

(iv)(A) The Regional Transmission Organization must provide:

(*1*) With respect to any Regional Transmission Organization in which market participants have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after approval of the Regional Transmission Organization, and every three years thereafter, unless otherwise provided by the Commission.

(*2*) With respect to any Regional Transmission Organization in which market participants have a role in the Regional Transmission Organization's decision making process but do not have an ownership interest, a compliance audit of the independence of the Regional Transmission Organization's decision making process under paragraph (j)(1)(ii) of this section, to be performed two years after its approval as a Regional Transmission Organization.

(B) The compliance audits under paragraph (j)(1)(iv)(A) of this section must be performed by auditors who are not affiliated with the Regional Transmission Organization or transmission facility owners that are members of the Regional Transmission Organization.

(2) *Scope and regional configuration*. The Regional Transmission Organization must serve an appropriate region. The region must be of sufficient scope and configuration to permit the Regional Transmission Organization to maintain reliability, effectively perform its required functions, and support efficient and non-discriminatory power markets.

(3) *Operational authority*. The Regional Transmission Organization must have operational authority for all transmission facilities under its control. The Regional Transmission Organization must include, as part of its demonstration of operational authority, a demonstration that it meets the following:

(i) If any operational functions are delegated to, or shared with, entities other than the Regional Transmission Organization, the Regional Transmission Organization must ensure that this sharing of operational authority will not adversely affect reliability or provide any market participant with an unfair competitive advantage. Within two years after initial operation as a Regional Transmission Organization, the Regional Transmission Organization must prepare a public report that assesses whether any division of operational authority hinders the Regional Transmission Organization in providing reliable, non-discriminatory and efficiently priced transmission service.

(ii) The Regional Transmission Organization must be the security coordinator for the facilities that it controls.

(4) *Short-term reliability*. The Regional Transmission Organization must have exclusive authority for maintaining the short-term reliability of the grid that it operates. The Regional Transmission Organization must include, as part of its demonstration with respect to reliability, a demonstration that it meets the following:

(i) The Regional Transmission Organization must have exclusive authority for receiving, confirming and implementing all interchange schedules.

(ii) The Regional Transmission Organization must have the right to order redispatch of any generator connected

to transmission facilities it operates if necessary for the reliable operation of these facilities.

(iii) When the Regional Transmission Organization operates transmission facilities owned by other entities, the Regional Transmission Organization must have authority to approve or disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards.

(iv) If the Regional Transmission Organization operates under reliability standards established by another entity (*e.g.*, a regional reliability council), the Regional Transmission Organization must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service.

(k) *Required functions of a Regional Transmission Organization*. The Regional Transmission Organization must perform the following functions. Unless otherwise noted, the Regional Transmission Organization must satisfy these obligations when it commences operations.

(1) *Tariff administration and design*. The Regional Transmission Organization must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. As part of its demonstration with respect to tariff administration and design, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(1)(i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.

(ii) Customers under the Regional Transmission Organization tariff must not be charged multiple access fees for the recovery of capital costs for transmission service over facilities that the Regional Transmission Organization controls.

(2) *Congestion management*. The Regional Transmission Organization must ensure the development and operation of market mechanisms to manage transmission congestion. As part of its demonstration with respect to congestion management, the Regional Transmission Organization must satisfy the standards listed in paragraph (k)(2)(i) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. The Regional Transmission Organization must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant.

(ii) The Regional Transmission Organization must satisfy the market mechanism requirement no later than one year after it commences initial operation. However, it must have in place at the time of initial operation an effective protocol for managing congestion.

(3) *Parallel path flow*. The Regional Transmission Organization must develop and implement procedures to address parallel path flow issues within its region and with other regions. The Regional Transmission Organization must satisfy this requirement with respect to coordination with other regions no later than three years after it commences initial operation.

(4) *Ancillary services*. The Regional Transmission Organization must serve as a provider of last resort of all ancillary services required by Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶ 31,036 (Final Rule on Open Access and Stranded Costs; see 61 FR 21540, May 10, 1996), and subsequent orders.

As part of its demonstration with respect to ancillary services, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(4)(i) through (iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any restrictions imposed by the Commission in Order No. 888, FERC Statutes and Regulations, Regulations Preamble January 1991–June 1996 ¶31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

(ii) The Regional Transmission Organization must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the Regional Transmission Organization. The Regional Transmission Organization must promote the development of competitive markets for ancillary services whenever feasible.

(iii) The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant.

(5) *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).* The Regional Transmission Organization must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.

(6) *Market monitoring.* To ensure that the Regional Transmission Organization provides reliable, efficient and not unduly discriminatory transmission service, the Regional Transmission Organization must provide for objective monitoring of markets it operates or administers to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions. As part of its demonstration with respect to market monitoring, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(6)(i) through (k)(6)(iii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) Market monitoring must include monitoring the behavior of market participants in the region, including transmission owners other than the Regional Transmission Organization, if any, to determine if their actions hinder the Regional Transmission Organization in providing reliable, efficient and not unduly discriminatory transmission service.

(ii) With respect to markets the Regional Transmission Organization operates or administers, there must be a periodic assessment of how behavior in markets operated by others (*e.g.*, bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects Regional Transmission Organization operations and how Regional Transmission Organization operations affect the efficiency of power markets operated by others.

(iii) Reports on opportunities for efficiency improvement, market power abuses and market design flaws must be filed with the Commission and affected regulatory authorities.

(7) *Planning and expansion.* The Regional Transmission Organization must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. As part of its demonstration with respect to planning and expansion, the Regional Transmission Organization must satisfy the standards listed in paragraphs (k)(7)(i) and (ii) of this section, or demonstrate that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization planning and expansion process must encourage market-driven operating and investment actions for preventing and relieving congestion.

(ii) The Regional Transmission Organization's planning and expansion process must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Regional Transmission Organization's planning and expansion process must be coordinated with programs of existing Regional Transmission Groups (See § 2.21 of this chapter) where appropriate.

(iii) If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file with the Commission a plan with specified milestones that will ensure that it meets this requirement no later than three years after initial operation.

(8) *Interregional coordination.* The Regional Transmission Organization must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

(l) *Open architecture.* (1) Any proposal to participate in a Regional Transmission Organization must not contain any provision that would limit the capability of the Regional Transmission Organization to evolve in ways that would improve its efficiency, consistent with the requirements in paragraphs (j) and (k) of this section.

(2) Nothing in this regulation precludes an approved Regional Transmission Organization from seeking to evolve with respect to its organizational design, market design, geographic scope, ownership arrangements, or methods of operational control, or in other appropriate ways if the change is consistent with the requirements of this section. Any future filing seeking approval of such changes must demonstrate that the proposed changes will meet the requirements of paragraphs (j), (k) and (l) of this section.

[Order 2000–A, 65 FR 12110, Mar. 8, 2000, as amended by Order 679, 71 FR 43338, July 31, 2006]

Subpart G—Transmission Infrastructure Investment Provisions

§ 35.35 Transmission infrastructure investment.

(a) *Purpose.* This section establishes rules for incentive-based (including performance-based) rate treatments for transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

(b) *Definitions.* (1) *Transco* means a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.

(2) *Transmission Organization* means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.

(c) *General rule.* All rates approved under the rules of this section, including any revisions to the rules, are subject to the filing requirements of sections 205 and 206 of the Federal Power Act and to the substantive requirements of sections 205 and 206 of the Federal Power Act that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.

(d) *Incentive-based rate treatments for transmission infrastructure investment.* The Commission will authorize any incentive-based rate treatment, as discussed in this paragraph (d), for transmission infrastructure investment, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. A public utility's request for one or more incentive-based rate treatments, to be made in a filing pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205, must include a detailed explanation of how the proposed

rate treatment complies with the requirements of section 219 of the Federal Power Act and a demonstration that the proposed rate treatment is just, reasonable, and not unduly discriminatory or preferential. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable. For purposes of this paragraph (d), incentive-based rate treatment means any of the following:

(1) For purposes of this paragraph (d), incentive-based rate treatment means any of the following:

(i) A rate of return on equity sufficient to attract new investment in transmission facilities;

(ii) 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base;

(iii) Recovery of prudently incurred pre-commercial operations costs;

(iv) Hypothetical capital structure;

(v) Accelerated depreciation used for rate recovery;

(vi) Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility;

(vii) Deferred cost recovery; and

(viii) Any other incentives approved by the Commission, pursuant to the requirements of this paragraph, that are determined to be just and reasonable and not unduly discriminatory or preferential.

(2) In addition to the incentives in § 35.35(d)(1), the Commission will authorize the following incentive-based rate treatments for Transcos, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential:

(i) A return on equity that both encourages Transco formation and is sufficient to attract investment; and

(ii) An adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.

(e) *Incentives for joining a Transmission Organization.* The Commission will authorize an incentive-based rate treatment, as discussed in this paragraph (e), for public utilities that join a Transmission Organization, if the applicant demonstrates that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the Federal Power Act. For purposes of this paragraph (e), an incentive-based rate treatment means a return on equity that is higher than the return on equity the Commission might otherwise allow if the public utility did not join a Transmission Organization. The Commission will also permit transmitting utilities or electric utilities that join a Transmission Organization the ability to recover prudently incurred costs associated with joining the Transmission Organization, either through transmission rates charged by transmitting utilities or electric utilities or through transmission rates charged by the Transmission Organization that provides services to such utilities.

(f) *Approval of prudently-incurred costs.* The Commission will approve recovery of prudently-incurred costs necessary to comply with the mandatory reliability standards pursuant to section 215 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(g) *Approval of prudently incurred costs related to transmission infrastructure development.* The Commission will approve recovery of prudently-incurred costs related to transmission infrastructure development pursuant to section 216 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(h) *FERC–730, Report of transmission investment activity.* Public utilities that have been granted incentive rate treatment for specific transmission projects

must file FERC–730 on an annual basis beginning with the calendar year incentive rate treatment is granted by the Commission. Such filings are due by April 18 of the following calendar year and are due April 18 each year thereafter. The following information must be filed:

(1) In dollar terms, actual transmission investment for the most recent calendar year, and projected, incremental investments for the next five calendar years;

(2) For all current and projected investments over the next five calendar years, a project by project listing that specifies for each project the most up-to-date, expected completion date, percentage completion as of the date of filing, and reasons for delays. Exclude from this listing projects with projected costs less than $20 million; and

(3) For good cause shown, the Commission may extend the time within which any FERC–730 filing is to be filed or waive the requirements applicable to any such filing.

(i) *Rebuttable presumption.* (1) The Commission will apply a rebuttable presumption that an applicant has demonstrated that its project is needed to ensure reliability or reduces the cost of delivered power by reducing congestion for:

(i) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or

(ii) A project that has received construction approval from an appropriate state commission or state siting authority.

(2) To the extent these approval processes do not require that a project ensures reliability or reduce the cost of delivered power by reducing congestion, the applicant bears the burden of demonstrating that its project satisfies these criteria.

(j) *Commission authorization to site electric transmission facilities in interstate commerce.* If the Commission pursuant to its authority under section 216 of the Federal Power Act and its regulations thereunder has issued one or more permits for the construction or modification of transmission facilities in a national interest electric transmission corridor designated by the Secretary, such facilities shall be deemed to either ensure reliability or reduce the cost of delivered power by reducing congestion for purposes of section 219(a).

[Order 679, 71 FR 43338, July 31, 2006, as amended by Order 679–A, 72 FR 1172, Jan. 10, 2007, Order 691, 72 FR 5174, Feb. 5, 2007]

Subpart H—Wholesale Sales of Electric Energy, Capacity and Ancillary Services at Market-Based Rates

SOURCE: Order 697, 72 FR 40038, July 20, 2007, unless otherwise noted.

§ 35.36 Generally.

(a) For purposes of this subpart:

(1) *Seller* means any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the Federal Power Act.

(2) *Category 1 Seller* means a Seller that:

(i) Is either a wholesale power marketer that controls or is affiliated with 500 MW or less of generation in aggregate per region or a wholesale power producer that owns, controls or is affiliated with 500 MW or less of generation in aggregate in the same region as its generation assets;

(ii) Does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or has been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶31,036);

(iii) Is not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the Seller's generation assets;

(iv) Is not affiliated with a franchised public utility in the same region as the Seller's generation assets; and

(v) Does not raise other vertical market power issues.

(3) *Category 2 Sellers* means any Sellers not in Category 1.

(4) *Inputs to electric power production* means intrastate natural gas transportation, intrastate natural gas storage

or distribution facilities; physical coal supply sources and ownership of or control over who may access transportation of coal supplies;

(5) *Franchised public utility* means a public utility with a franchised service obligation under State law.

(6) *Captive customers* means any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.

(7) *Market-regulated power sales affiliate* means any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part on a market-rate basis.

(8) *Market information* means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.

(9) *Affiliate* of a specified company means:

(i) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company;

(ii) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company;

(iii) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and

(iv) Any person that is under common control with the specified company.

(v) For purposes of paragraph (a)(9), owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control.

(b) The provisions of this subpart apply to all Sellers authorized, or seeking authorization, to make sales for resale of electric energy, capacity or ancillary services at market-based rates unless otherwise ordered by the Commission.

[Order 697, 72 FR 40038, July 20, 2007, as amended by Order 697–A, 73 FR 25912, May 7, 2008; Order 697–B, 73 FR 79627, Dec. 30, 2008; Order 816, 80 FR 67108, Oct. 30, 2015; Order 816–A, 81 FR 33383, May 26, 2016]

§ 35.37 Market power analysis required.

(a) (1) In addition to other requirements in subparts A and B, a Seller must submit a market power analysis in the following circumstances: when seeking market-based rate authority; for Category 2 Sellers, every three years, according to the schedule posted on the Commission's Web site; or any other time the Commission directs a Seller to submit one. Failure to timely file an updated market power analysis will constitute a violation of Seller's market-based rate tariff.

(2) When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets, in the form provided in appendix B of this subpart, and an organizational chart. The organizational chart must depict the Seller's current corporate structure indicating all affiliates.

(b) A market power analysis must address whether a Seller has horizontal and vertical market power.

(c)(1) There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, and primary frequency response service if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of operating reserve-spinning and operating reserve-supplemental services if

the Seller passes these two indicative market power screens and demonstrates in its market-based rate application how the scheduling practices in its region support the delivery of operating reserve resources from one balancing authority area to another. There will be a rebuttable presumption that a Seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, operating reserve-spinning service, operating reserve-supplemental service, and primary frequency response service if it fails either screen.

(2) Sellers and intervenors may also file alternative evidence to support or rebut the results of the indicative screens. Sellers may file such evidence at the time they file their indicative screens. Intervenors may file such evidence in response to a Seller's submissions.

(3) If a Seller does not pass one or both screens, the Seller may rebut a presumption of horizontal market power by submitting a Delivered Price Test analysis. A Seller that does not rebut a presumption of horizontal market power or that concedes market power, is subject to mitigation, as described in § 35.38.

(4) When submitting the indicative screens, a Seller must use the format provided in appendix A of this subpart and file the indicative screens in an electronic spreadsheet format. A Seller must include all supporting materials referenced in the indicative screens.

(5) Sellers submitting simultaneous transmission import limit studies must file Submittal 1, and, if applicable, Submittal 2, in the electronic spreadsheet format provided on the Commission's Web site.

(d) To demonstrate a lack of vertical market power, a Seller that owns, operates or controls transmission facilities, or whose affiliates own, operate or control transmission facilities, must have on file with the Commission an Open Access Transmission Tariff, as described in § 35.28; provided, however, that a Seller whose foreign affiliate(s) own, operate or control transmission facilities outside of the United States that can be used by competitors of the Seller to reach United States markets must demonstrate that such affiliate either has adopted and is implementing an Open Access Transmission Tariff as described in § 35.28, or otherwise offers comparable, non-discriminatory access to such transmission facilities.

(e) To demonstrate a lack of vertical market power in wholesale energy markets through the affiliation, ownership or control of inputs to electric power production, such as the transportation or distribution of the inputs to electric power production, a Seller must provide the following information:

(1) A description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities;

(2) Physical coal supply sources and ownership or control over who may access transportation of coal supplies; and

(3) A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it and its affiliates have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

(f) If the Seller seeks to protect any portion of a filing from public disclosure, the Seller must make its filing in accordance with the Commission's instructions for filing privileged materials and critical energy infrastructure information in § 388.112 of this chapter.

[Order 697, 72 FR 40038, July 20, 2007, as amended by Order 697–B, 73 FR 79627, Dec. 30, 2008; Order 769, 77 FR 65475, Oct. 29, 2012; Order 784, 78 FR 46209, July 30, 2013; Order 816, 80 FR 67108, Oct. 30, 2015; Order 819, 80 FR 73977, Nov. 27, 2015]

§ 35.38 Mitigation.

(a) A Seller that has been found to have market power in generation or ancillary services, or that is presumed to have horizontal market power in generation or ancillary services by virtue of failing or foregoing the relevant market power screens, as described in 35.37(c), may adopt the default mitigation detailed in paragraph (b) of this

section for sales of energy or capacity or paragraph (c) of this section for sales of ancillary services or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power. Mitigation will apply only to the market(s) in which the Seller is found, or presumed, to have market power.

(b) Default mitigation for sales of energy or capacity consists of three distinct products:

(1) Sales of power of one week or less priced at the Seller's incremental cost plus a 10 percent adder;

(2) Sales of power of more than one week but less than one year priced at no higher than a cost-based ceiling reflecting the costs of the unit(s) expected to provide the service; and

(3) New contracts filed for review under section 205 of the Federal Power Act for sales of power for one year or more priced at a rate not to exceed embedded cost of service.

(c) Default mitigation for sales of ancillary services consist of: (1) A cap based on the relevant OATT ancillary service rate of the purchasing transmission operator; or (2) the results of a competitive solicitation that meets the Commission's requirements for transparency, definition, evaluation, and competitiveness.

[Order 697, 72 FR 40038, July 20, 2007, as amended by Order 784, 78 FR 46210, July 30, 2013]

§ 35.39 Affiliate restrictions.

(a) *General affiliate provisions.* As a condition of obtaining and retaining market-based rate authority, the conditions provided in this section, including the restriction on affiliate sales of electric energy and all other affiliate provisions, must be satisfied on an ongoing basis, unless otherwise authorized by Commission rule or order. Failure to satisfy these conditions will constitute a violation of the Seller's market-based rate tariff.

(b) *Restriction on affiliate sales of electric energy or capacity.* As a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy or capacity may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act. All authorizations to engage in affiliate wholesale sales of electric energy or capacity must be listed in a Seller's market-based rate tariff.

(c) *Separation of functions.* (1) For the purpose of this paragraph, entities acting on behalf of and for the benefit of a franchised public utility with captive customers (such as entities controlling or marketing power from the electrical generation assets of the franchised public utility) are considered part of the franchised public utility. Entities acting on behalf of and for the benefit of the market-regulated power sales affiliates of a franchised public utility with captive customers are considered part of the market-regulated power sales affiliates.

(2) (i) To the maximum extent practical, the employees of a market-regulated power sales affiliate must operate separately from the employees of any affiliated franchised public utility with captive customers.

(ii) Franchised public utilities with captive customers are permitted to share support employees, and field and maintenance employees with their market-regulated power sales affiliates. Franchised public utilities with captive customers are also permitted to share senior officers and boards of directors with their market-regulated power sales affiliates; provided, however, that the shared officers and boards of directors must not participate in directing, organizing or executing generation or market functions.

(iii) Notwithstanding any other restrictions in this section, in emergency circumstances affecting system reliability, a market-regulated power sales affiliate and a franchised public utility with captive customers may take steps necessary to keep the bulk power system in operation. A franchised public utility with captive customers or the market-regulated power sales affiliate must report to the Commission and disclose to the public on its Web site, each emergency that resulted in any deviation from the restrictions of section 35.39, within 24 hours of such deviation.

(d) *Information sharing.* (1) A franchised public utility with captive customers may not share market information with a market-regulated power sales affiliate if the sharing could be used to the detriment of captive customers, unless simultaneously disclosed to the public.

(2) Permissibly shared support employees, field and maintenance employees and senior officers and board of directors under §§ 35.39(c)(2)(ii) may have access to information covered by the prohibition of § 35.39(d)(1), subject to the no-conduit provision in § 35.39(g).

(e) *Non-power goods or services.* (1) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a franchised public utility with captive customers, to a market-regulated power sales affiliate must be at the higher of cost or market price.

(2) Unless otherwise permitted by Commission rule or order, sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers may not be at a price above market.

(f) *Brokering of power.* (1) Unless otherwise permitted by Commission rule or order, to the extent a market-regulated power sales affiliate seeks to broker power for an affiliated franchised public utility with captive customers:

(i) The market-regulated power sales affiliate must offer the franchised public utility's power first;

(ii) The arrangement between the market-regulated power sales affiliate and the franchised public utility must be non-exclusive; and

(iii) The market-regulated power sales affiliate may not accept any fees in conjunction with any brokering services it performs for an affiliated franchised public utility.

(2) Unless otherwise permitted by Commission rule or order, to the extent a franchised public utility with captive customers seeks to broker power for a market-regulated power sales affiliate:

(i) The franchised public utility must charge the higher of its costs for the service or the market price for such services;

(ii) The franchised public utility must market its own power first, and simultaneously make public (on the Internet) any market information shared with its affiliate during the brokering; and

(iii) The franchised public utility must post on the Internet the actual brokering charges imposed.

(g) *No conduit provision.* A franchised public utility with captive customers and a market-regulated power sales affiliate are prohibited from using anyone, including asset managers, as a conduit to circumvent the affiliate restrictions in §§ 35.39(a) through (g).

(h) *Franchised utilities without captive customers.* If necessary, any affiliate restrictions regarding separation of functions, power sales or non-power goods and services transactions, or brokering involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not have captive customers, will be imposed on a case-by-case basis.

[Order 697, 72 FR 40038, July 20, 2007, as amended by Order 697–A, 73 FR 25912, May 7, 2008]

§ 35.40 Ancillary services.

A Seller may make sales of ancillary services at market-based rates only if it has been authorized by the Commission and only in specific geographic markets as the Commission has authorized.

§ 35.41 Market behavior rules.

(a) *Unit operation.* Where a Seller participates in a Commission-approved organized market, Seller must operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission-approved rules and regulations of the applicable market. A Seller is not required to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or is a requirement applicable to Seller through Seller's participation in a Commission-approved organized market.

(b) *Communications.* A Seller must provide accurate and factual information and not submit false or misleading

information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.

(c) *Price reporting.* To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the *Policy Statement on Natural Gas and Electric Price Indices,* issued by the Commission in Docket No. PL03–3–000, and any clarifications thereto. Seller must identify as part of its Electric Quarterly Report filing requirement in § 35.10b of this chapter the publishers of electricity and natural gas indices to which it reports its transactions. In addition, Seller must adhere to any other standards and requirements for price reporting as the Commission may order.

(d) *Records retention.* A Seller must retain, for a period of five years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to Seller's market-based rate tariff, and the prices it reported for use in price indices.

[Order 697, 72 FR 40038, July 20, 2007, as amended by Order 768, 77 FR 61924, Oct. 11, 2012]

§ 35.42 Change in status reporting requirement.

(a) As a condition of obtaining and retaining market-based rate authority, a Seller must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. A change in status includes, but is not limited to, the following:

(1) Ownership or control of generation capacity or long-term firm purchases of capacity and/or energy that results in cumulative net increases (*i.e.,* the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of capacity based on nameplate or seasonal capacity ratings, or, for solar photovoltaic facilities, nameplate capacity, or, for other energy-limited resources, nameplate or five-year average capacity factors, in any individual relevant geographic market, or of inputs to electric power production, or ownership, operation or control of transmission facilities; or

(2) Affiliation with any entity not disclosed in the application for market-based rate authority that:

(i) Owns or controls generation facilities or has long-term firm purchases of capacity and/or energy that results in cumulative net increases (*i.e.,* the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of capacity based on nameplate or seasonal capacity ratings, or, for solar photovoltaic facilities, nameplate capacity, or, for other energy-limited resources, nameplate or five-year average capacity factors, in any individual relevant geographic market;

(ii) Owns or controls inputs to electric power production;

(iii) Owns, operates or controls transmission facilities; or

(iv) Has a franchised service area.

(b) Any change in status subject to paragraph (a) of this section must be filed no later than 30 days after the change in status occurs. Power sales contracts with future delivery are reportable 30 days after the physical delivery has begun. Failure to timely file a change in status report constitutes a tariff violation.

(c) When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of all assets, including the new assets and/or affiliates reported in the change in status, in the form provided in appendix B of this subpart, and an organizational chart. The organizational chart must depict the Seller's prior and new corporate structures indicating all affiliates unless the Seller demonstrates

that the change in status does not affect the corporate structure of the Seller's affiliations.

[Order 697–D, 75 FR 14351, Mar. 25, 2010, as amended by Order 816, 80 FR 67108, Oct. 30, 2015; Order 816–A, 81 FR 33383, May 26, 2016]

Appendix A to Subpart H of Part 35—Standard Screen Format

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part I – Pivotal Supplier Analysis

Staff Notes:

The file differs from the file published in the NOPR:
1. All entered values must be positive (no parenthesis/negative numbers)
2. The formulas (and the text in the row description) have been changed to reflect number 1.
3. The text in row 13 "Date of Filing" has been replaced with "Data Year"
4. Instruction: *Enter all numeric values as positive numbers (blue values)*

Don't enter values into an outlined cell (black values)

Applicant-> **Company X, LLC (TO)**
Market -> **Company X BAA**
Data Year -> **Dec 2011-Nov 2012**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	1,500	worksheet X
A1	Remote Capacity (from outside the study area)	200	worksheet X
B	Long-Term Firm Purchases (from inside the study area)	70	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	500	worksheet X
D	Uncommitted Capacity Imports	0	worksheet X
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	300	worksheet X
E1	Remote Capacity (from outside the study area)	50	worksheet X
F	Long-Term Firm Purchases (from inside the study area)	40	worksheet X
F1	Long-Term Firm Purchases (from outside the study area)	40	worksheet X
G	Long-Term Firm Sales (in and outside the study area)	60	worksheet X
H	Uncommitted Capacity Imports	2,500	worksheet X
I	Study Area Reserve Requirement	300	worksheet X
J	Amount of Line I Attributable to Seller, if any	200	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,840	
	Load		
L	Balancing Authority Area Annual Peak Load	1,500	worksheet X
M	Average Daily Peak Native Load in Peak Month	1,200	worksheet X
N	Amount of Line M Attributable to Seller, if any	900	worksheet X
O	Wholesale Load (L-M)	300	
P	Net Uncommitted Supply (K-O)	2,540	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	370	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D,H), as filed by Seller ->	2,500
% of SIL for Seller's imported capacity ->	0.00
% of SIL for Other's imported capacity ->	1.00
SIL value* ->	2,500
Do Total Imports exceed the SIL value? ->	No

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part II – Market Share Analysis

Staff Notes:

The file differs from the file published in the NOPR:

1. All entered values must be positive (no parenthesis/negative numbers)
2. The formulas (and the text in the row description) have been changed to reflect number 1.
3. Instruction: *Enter all numeric values as positive numbers (blue values)*

Don't enter values into an outlined cell (black values)

Applicant-> **Company X, LLC (TO)**
Study Area -> **Company X BAA**
Data Year -> **Dec 2011-Nov 2012**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	1,000	900	1,500	1,000	worksheet X
A1	Remote Capacity (from outside the study area)	400	300	200	200	worksheet X
B	Long-Term Firm Purchases (inside the study area)	60	40	70	30	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	200	200	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	500	500	500	500	worksheet X
D	Seasonal Average Planned Outages	150	50	80	100	worksheet X
E	Uncommitted Capacity Imports	0	0	0	0	worksheet X
	Capacity Deductions					
F	Average Peak Native Load in the Season	1,000	900	1,200	800	worksheet X
G	Amount of Line F Attributable to Seller, if any	700	700	900	600	worksheet X
H	Amount of Line F Attributable to Non-Affiliates, if any	300	200	300	200	
I	Study Area Reserve Requirement	200	200	300	100	worksheet X
J	Amount of Line I Attributable to Seller, if any	100	100	200	80	worksheet X
K	Amount of Line I Attributable to Non-Affiliates, if any	100	100	100	20	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	250	200	300	150	worksheet X
L1	Remote Capacity (from outside the study area)	50	50	50	50	worksheet X
M	Long-Term Firm Purchases (inside the study area)	30	30	30	30	worksheet X
M1	Long-Term Firm Purchases (from outside the study area)	40	30	40	20	worksheet X
N	Long-Term Firm Sales (in and outside the study area)	50	30	60	50	worksheet X
O	Seasonal Average Planned Outages	10	20	10	20	worksheet X
P	Uncommitted Capacity Imports	2,000	1,500	2,500	1,300	worksheet X
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	1,910	1,460	2,450	1,260	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	210	90	290	150	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,120	1,550	2,740	1,410	
T	**Seller's Market Share** (R÷S)	9.9%	5.8%	10.6%	10.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	2,000	1,500	2,500	1,300	
V	SIL value*	2,000	1,500	2,500	1,300	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

[Order 816, 80 FR 67108, Oct. 30, 2015]

Appendix B to Subpart H of Part 35—Corporate Entities and Assets Sample Appendix

	Instructions for completing the Asset Appendix Sheet: Generation Assets		
Column	**Title**	**Format**	**Description**
[A]	Filing Entity and its Energy Affiliates	Free Form Text	Name of the Filing Entity and its Affiliates. Please use the exact name as in the Company Registration database if possible.
[B]	Docket # where MBR authority was granted	Text in the form: ERXX-XXX-XXX where "X" is a digit	If applicable, Docket Number where MBR was originally granted.
[C]	Generation Name (Plant or Unit Name)	Free Form Text	Unit Name or if all units in a plant are reasonably similar, a plant name. Use EIA-860 or industry standard names to the extent possible.
[D]	Owned By	Free Form Text	Name of the Entity owning the generation unit or plant. Please use the same name as in the Company Registration database if possible.
[E]	Controlled By	Free Form Text	Name of the Entity that controls the output of the generation unit or plant. Please use the same name as in the Company Registration database if possible.
[F]	Date Control Transferred	MM/YYYY or DD/MM/YY	The date the unit came under the control of the Entity listed in "[E] Controlled By." Often it is the date the generation was acquired or built.
[G]	Location: Market/Balancing Authority Area	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name.
[H]	Location: Geographic Region	Specific Text	One of the six MBR regions: Northeast, Southeast, Central, SPP, Northwest, Southwest.
[I]	In-Service Date	MM/YYYY or MM/DD/YY	The date the unit first came into service.
[J]	Capacity Rating: Nameplate (MW)	Numeric. Either an integer or fixed width numeric with one decimal	The nameplate capacity rating of the unit, usually provided by the manufacturer, in MWs.
[K]	Capacity Rating: Used in Filing (MW)	Numeric. Either an integer or fixed width numeric with one decimal	The capacity rating of the unit(s), in MWs, used in this filing.
[L]	Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative		A single capital letter (either "N", "S","U","E", or "A") to designate the rating methodology of the unit's capacity used in this filing. Describe "Alternative" Capacity Rating Method in End Notes Sheet.
[M]	End Note Number (Enter text in End Notes Sheet)	Integer	The number of the explanatory note in End Notes Sheet that refers to this entry. The numbers should be ascending integers throughout the appendix. If there are three notes in the Generation Assets Sheet, then the first end note in the next asset sheet should be four (please do not start over with a new numbering sequence).

	Instructions for completing the Asset Appendix Sheet: Long-Term Firm Power Purchase Agreements (PPA)		
Column	**Title**	**Format**	**Description**
[A]	Filing Entity and its Energy Affiliates	Free Form Text	Name of the Filing Entity or affiliate of the Filing Entity that is purchasing the energy or capacity.
[B]	Seller Name	Free Form Text	Name of the Filing Entity that is selling the capacity and/or energy. Please use the exact name as in the Company Registration database if possible.
[C]	Amount of PPA (MW)	Numeric. Either an integer or fixed width numeric with one decimal	Contracted amount of the PPA in MW. If the contract is for the entire output of a specific generation unit, you may de-rate the unit using the same de-rating methodology that is used for generators of the same technology elsewhere in the appendix. If this amount is de-rated please explain in the End Notes Sheet. Energy-only contracts must be converted from MWh to MW. Only report contracts one year or longer.
[D]	Location: Market/Balancing Authority Area (Source)	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name. For "System" PPAs, identify all markets and balancing authority areas from which the PPA is sourced to the extent the source location(s) is specified in the PPA.
[E]	Location: Market/Balancing Authority Area (Sink)	Free Form Text. For Markets or submarkets please use one of the abbreviations or names in the next column. For balancing authority areas please use the NERC-defined name	One of the six RTO/ISOs (ISO-NE, NYISO, PJM, MISO, SPP, CAISO) or their designated submarkets (PJM-East, 5004/5005, AP South, Connecticut, Southwest Connecticut, New York City, Long Island) or a NERC-defined Balancing Authority Area name. For all PPAs, identify where the capacity and/or energy is delivered.
[F]	Location: Geographic Region (Sink)	Specific Text	Same instruction as the Generation Assets Sheet.
[G]	Start Date (mo/da/yr)	MM/DD/YY	The Start Date of the PPA
[H]	End Date (mo/da/yr)	MM/DD/YY	The End Date of the PPA
[I]	Type of PPA (Unit or System)	"Unit" or "System"	Enter the text "Unit" if the PPA is from a specific unit such as a wind generator selling its output to a utility, or from multiple units at a single plant. Please provide the name of the unit or facility supplying the PPA in the End Notes Sheet. Enter "System" if the PPA is sourced from a utility's or IPP's fleet with different units providing power at different times.
[J]	End Note Number (Enter text in End Notes Sheet)	Integer	Same instruction as the Generation Assets Sheet.

	Instructions for completing the Asset Appendix Sheet: Transmission/Natural Gas Assets		
Column	**Title**	**Format**	**Description**
[A]	Filing Entity and its Energy Affiliates		Same instruction as the Generation Assets Sheet.
[B]	Cite to order accepting OATT or the order approving the transfer of transmission facilities to an RTO or ISO		Commission cite to the order accepting the Filing Entity's or its Energy Affiliate's current OATT, or the order transferring control of the transmission facilities to an RTO/ISO.
[C]	Asset Name and Use	Free Form Text	Legal name of the facility and brief description of the type of facility (i.e. transmission line or gas pipeline).
[D]	Owned By		Name of the Entity owning the transmission/natural gas assets.
[E]	Controlled By		Name of the Entity that controls the transmission/natural gas assets.
[F]	Date Control Transferred		Same instruction as the Generation Assets Sheet.
[G]	Market/Balancing Authority Area		Same instruction as the Generation Assets Sheet.
[H]	Geographic Region		Same instruction as the Generation Assets Sheet.
[I]	Size (e.g., length and kV for electric, length and diameter for pipelines, and capacity for gas storage)	Free Form Text	Description of the size of the facility in the measures relevant to the specific type of facility. For example, for electric "Size" refers to the length and kV rating of the transmission line; for gas pipeline "Size" refers to the length and diameter of the pipeline; for gas storage "Size" refers to the capacity of the facility.
[J]	End Note Number (Enter text in End Notes Sheet)		Same instruction as the Generation Assets Sheet.

	Instructions for completing the Asset Appendix Sheet: End Notes		
Column	Title	Format	Description
[A]	End Note Number	Integer	Should match an End Note number in the Generation Assets, Long-Term Firm PPAs or Transmission/Natural Gas Assets Sheets.
[B]	Sheet (Generation Assets, Long-Term Firm PPAs or Transmission/Natural Gas Assets)	The words "Generation", "PPA", or "Transmission/Natural Gas"	Indicates in which asset sheet the End Note is located.
[C]	Explanatory Note	Free Form Text	Text providing the clarification or explanatory note.

This is an example of the required appendix listing the filing entity and all its energy affiliates and their associated assets, which must be submitted with relevant market-based rate filings.

Asset Appendix: Generation Assets

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
						Location						
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority Area	Geographic Region	In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet)

Asset Appendix: Long-Term Firm Power Purchase Agreements (PPA)

Note:
Energy-only contracts must be converted to MW
Only report contracts one year or longer

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
			Location						
Filing Entity and its Energy Affiliates	Seller Name	Amount of PPA (MW)	Market / Balancing Authority Area (Source)	Market / Balancing Authority Area (Sink)	Geographic Region (Sink)	Start Date (mo/da/yr)	End Date (mo/da/yr)	Type of PPA (Unit or System)	End Note Number (Enter text in End Notes Sheet)

Asset Appendix: Transmission/Natural Gas Assets

Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location		Size	
Filing Entity and its Energy Affiliates	Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority Area	Geographic Region	Size (e.g., length and kV for electric, length and diameter for pipelines, and capacity for gas storage)	End Note Number (Enter text in End Notes Sheet)

		Asset Appendix: End Notes
		End Notes for Entries in the Generation, Long-Term Firm PPA and Transmission/Natural Gas Assets Sheets
[A]	[B]	[C]
End Note Number	Sheet (Generation, PPA or Transmission / Natural Gas)	Explanatory Note

[Order 816–A, 81 FR 33383, May 26, 2016]

Subpart I—Cross-Subsidization Restrictions on Affiliate Transactions

SOURCE: 73 FR 11025, Feb. 29, 2008, unless otherwise noted.

§ 35.43 Generally.

(a) For purposes of this subpart:

(1) *Affiliate* of a specified company means:

(i) For any person other than an exempt wholesale generator:

(A) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company;

(B) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company;

(C) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and

(D) Any person that is under common control with the specified company.

(E) For purposes of paragraph (a)(1)(i) of this section, owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control.

(ii) For any exempt wholesale generator (as defined under §366.1 of this chapter), consistent with section 214 of the Federal Power Act (16 U.S.C. 824m), which provides that ''affiliate'' will have the same meaning as provided in section 2(a) of the Public Utility Holding Company Act of 1935 (15 U.S.C. 79b(a)(11)):

(A) Any person that directly or indirectly owns, controls, or holds with power to vote, 5 percent or more of the outstanding voting securities of the specified company;

(B) Any company 5 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company;

(C) Any individual who is an officer or director of the specified company, or of any company which is an affiliate thereof under paragraph (a)(1)(ii)(A) of this section; and

(D) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate.

(2) *Captive customers* means any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.

(3) *Franchised public utility* means a public utility with a franchised service obligation under state law.

(4) *Market-regulated power sales affiliate* means any power seller affiliate other than a franchised public utility, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, whose power sales are regulated in whole or in part on a market-rate basis.

(5) *Non-utility affiliate* means any affiliate that is not in the power sales or transmission business, other than a local gas distribution company or an interstate natural gas pipeline.

(b) The provisions of this subpart apply to all franchised public utilities that have captive customers or that own or provide transmission service over jurisdictional transmission facilities.

§ 35.44 Protections against affiliate cross-subsidization.

(a) *Restriction on affiliate sales of electric energy*. No wholesale sale of electric energy may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act. This requirement does not apply to energy sales from a qualifying facility, as defined by 18 CFR 292.101, made under market-based rate authority granted by the Commission.

(b) *Non-power goods or services*. (1) Unless otherwise permitted by Commission rule or order, and except as permitted by paragraph (b)(4) of this section, sales of any non-power goods or services by a franchised public utility that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, including sales made to or through its affiliated exempt wholesale generators or qualifying facilities, to a market-regulated power sales affiliate or non-utility affiliate must be at the higher of cost or market price.

(2) Unless otherwise permitted by Commission rule or order, and except as permitted by paragraphs (b)(3) and (b)(4) of this section, a franchised public utility that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, may not purchase or receive non-power goods and services from a market-regulated power sales affiliate or a non-utility affiliate at a price above market.

(3) A franchised public utility that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, may only purchase or receive non-power goods and services from a centralized service company at cost.

(4) A company in a single-state holding company system, as defined in § 366.3(c)(1) of this chapter, may provide general administrative and management non-power goods and services to, or receive such goods and services from, other companies in the same holding company system, at cost, provided that the only parties to transactions involving these non-power goods and services are affiliates or associate companies, as defined in § 366.1 of this chapter, of a holding company in the holding company system.

(c) *Exemption for price under fuel adjustment clause regulations*. Where the price of fuel from a company-owned or controlled source is found or presumed under § 35.14 to be reasonable and includable in the adjustment clause, transactions involving that fuel shall be exempt from the affiliate price restrictions in § 35.44(b).

[73 FR 11025, Feb. 29, 2008, as amended by Order 707–A, 73 FR 43083, July 24, 2008]

Subpart J—Credit Practices In Organized Wholesale Electric Markets

SOURCE: Order 741, 75 FR 65962, Oct. 27, 2010, unless otherwise noted.

§ 35.45 Applicability.

This subpart establishes credit practices for organized wholesale electric markets for the purpose of minimizing risk to market participants.

§ 35.46 Definitions.

As used in this subpart:

(a) *Market Participant* means an entity that qualifies as a Market Participant under § 35.34.

(b) *Organized Wholesale Electric Market* includes an independent system operator and a regional transmission organization.

(c) *Regional Transmission Organization* means an entity that qualifies as a Regional Transmission Organization under 18 CFR 35.34.

(d) *Independent System Operator* means an entity operating a transmission system and found by the Commission to be an Independent System Operator.

§ 35.47 Tariff provisions regarding credit practices in organized wholesale electric markets.

Each organized wholesale electric market must have tariff provisions that:

(a) Limit the amount of unsecured credit extended by an organized wholesale electric market to no more than $50 million for each market participant; where a corporate family includes more than one market participant participating in the same organized wholesale electric market, the limit on the amount of unsecured credit extended by that organized wholesale electric market shall be no more than $50 million for the corporate family.

(b) Adopt a billing period of no more than seven days and allow a settlement period of no more than seven days.

(c) Eliminate unsecured credit in financial transmission rights markets and equivalent markets.

(d) Establish a single counterparty to all market participant transactions, or require each market participant in an organized wholesale electric market to grant a security interest to the organized wholesale electric market in the receivables of its transactions, or provide another method of supporting netting that provides a similar level of protection to the market and is approved by the Commission. In the alternative, the organized wholesale electric market shall not net market participants' transactions and must establish credit based on market participants' gross obligations.

(e) Limit to no more than two days the time period provided to post additional collateral when additional collateral is requested by the organized wholesale electric market.

(f) Require minimum participation criteria for market participants to be eligible to participate in the organized wholesale electric market.

(g) Provide a list of examples of circumstances when a market administrator may invoke a ''material adverse change'' as a justification for requiring additional collateral; this list does not limit a market administrator's right to invoke such a clause in other circumstances.

[Order 741, 75 FR 65962, Oct. 27, 2010, as amended by Order 741–A, 76 FR 10498, Feb. 25, 2011]

PART 36—RULES CONCERNING APPLICATIONS FOR TRANSMISSION SERVICES UNDER SECTION 211 OF THE FEDERAL POWER ACT

AUTHORITY: 5 U.S.C. 551–557; 16 U.S.C. 791a–825r; 31 U.S.C. 9701; 42 U.S.C. 7107–7352.

§ 36.1 Notice provisions applicable to applications for transmission services under section 211 of the Federal Power Act.

(a) *Definitions.* (1) *Affected party* means each affected electric utility, each affected State regulatory authority, and each affected Federal power marketing agency.

(2) *Affected electric utility* means each electric utility that has made arrangements for the sale or purchase of electric energy to be transmitted pursuant to the particular application for transmission services, and each transmitting utility, as defined in section 3(23) of the Federal Power Act, 16 U.S.C. 796(23), being requested to transmit such electric energy.

(3) *Affected State regulatory authority* means a State regulatory authority, as defined in section 3(21) of the Federal Power Act, 16 U.S.C. 796(21), regulating the rates and charges of each affected electric utility.

(4) *Affected Federal power marketing agency* means a Federal power marketing agency that operates in the service area of each affected electric utility.