REQUEST FOR PROPOSAL

Issued by
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215

Evaluation of Duke Energy of Ohio Integrated Resource Plan
RFP Number 2010-05
Issued April 2, 2010

REQUEST FOR PROPOSAL
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Organization. This Request For Proposal is organized into five parts as listed below:

PART ONE: EXECUTIVE SUMMARY

Purpose. This is a Request for Proposal ("RFP") issued by the Office of the Ohio Consumers' Counsel ("OCC") to solicit proposals from Independent Contractors to provide assistance to the OCC in evaluating anticipated filings (see attached press releases and relevant Ohio law and regulations), primarily by Duke Energy before the Public Utilities Commission of Ohio ("PUCO" or "Commission") which will include an Integrated Resource Plan ("IRP") containing plans to build a nuclear generating plant (See part three: Scope of Work and Deliverables for details on this proceeding) and any related activities and proceedings.

Background. The OCC plays an integral part in Ohio's government and economy by fulfilling its role as the advocate agency for residential utility consumers. Established in 1976, the OCC participates in major rate, fuel, rule-making and federal cases affecting the utility service of Ohio's residential consumers.

The law governing the agency's activities is contained in Chapter 4911 of the Ohio Revised Code.

The Consumers' Counsel is appointed by and remains responsible to a nine-member Governing Board. The representative role of the Governing Board can be viewed as incorporating three broad functions: accountability to the Public, the General Assembly and the Attorney General; policy-making in directing the Consumers' Counsel; and oversight of the Consumers' Counsel Office.

The Consumers' Counsel appoints and administers a staff to carry out her legislative mandates. The office works to protect the interests of residential utility consumers, which is accomplished by formal case interventions, informal negotiation and dispute resolution, complaint and inquiry handling, educational efforts and analytical and legal assistance to legislators and others on public utility issues.

PART TWO: GENERAL INSTRUCTIONS

Calendar of Events. The schedule for this RFP and the work is given below. The OCC reserves the right to change this schedule as needed.

Firm Dates	
RFP Issued:	**April 2, 2010**
Proposal Due Date/Time:	**April 21 2010 at 5:00 p.m.**
Estimated Dates	
Contract Award:	**April 23, 2010**
Work Begins: If Controlling Board approval needed	**May 10, 2010**
If Controlling Board approval is not needed	**April 30, 2010**
Contract End Date	**June 30, 2011**

If the contractor awarded a contract under this RFP has total contracts or anticipated expenditures during the current state fiscal year totaling $50,000 or more, the OCC will seek approval from the State of Ohio Controlling Board for the use of funds for the contract associated with this RFP. The timing of that approval is dependent on the dates for submission to the Board and the scheduled meeting of the Board. The "work begins" dates above reflect OCC's current estimate of the timing of that approval process.

Contacts. The following individual will represent the OCC as the primary contact for matters relating to the non-technical aspects of the RFP and during the contract negotiation/award process and subsequent invoicing.

Robin Tedrick
Records Management Coordinator
Office of the Ohio Consumers' Counsel
10 W. Broad Street, Suite 1800
Columbus, Ohio 43215
614-466-9591
E-mail: tedrick@occ.state.oh.us

The following individual will represent the OCC as the primary contact for matters relating to technical aspects of the RFP and throughout the performance of the work upon the awarding of the contract.

Wilson Gonzalez
Principal Regulatory Analyst
Office of the Ohio Consumers' Counsel
10 W. Broad Street, Suite 1800
Columbus, Ohio 43215
614-466-9541
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Proposal Submission. Proposals are to be mailed or delivered to: Robin Tedrick, Office of the Ohio Consumers' Counsel, 10 W. Broad Street, Suite 1800, Columbus, Ohio 43215-3485. Proposals may also be faxed to (614) 728-7498 or submitted via e-mail to tedrick@occ.state.oh.us. The deadline to submit proposals for this RFP is ***5:00 p.m. on April 21, 2010.***

The OCC may reject any proposals or unsolicited proposal amendments that are received after the deadline. A prospective contractor that mails its proposal must allow for adequate mailing time to ensure its timely receipt.

Each prospective contractor must carefully review the requirements of this RFP and the contents of its proposal. All prospective contractors are on notice that the OCC will not be liable for any costs incurred by any prospective contractor in responding to this RFP, regardless of whether the OCC awards the contract through this process, decides not to go forward with the work, cancels this RFP for any reason, or contracts for the work through some other process or by issuing another RFP.

By submitting a proposal, the prospective contractor acknowledges that it has read this RFP, understands it, and agrees to be bound by its requirements. The prospective contractor also agrees that the contract will be the complete and exclusive statement of the agreement between the OCC and the contractor and will supersede all communications between the parties regarding the contract's subject matter.

The OCC may reject any proposal if the prospective contractor takes exception to the terms and conditions of this RFP, fails to comply with the procedure for participating in the RFP process, or the prospective contractor's proposal fails to meet any requirement of this RFP. The OCC may reject any proposal that is not in the best interest of the OCC to accept. Further, the OCC may decide not to do business with any of the prospective contractors responding to this RFP.

All proposals and other material submitted will become the property of the OCC and may be returned only at the option of the OCC. Proprietary information should not be included in a proposal or supporting materials because the OCC will have the right to use any materials or ideas submitted in any proposal without compensation to the prospective contractor.

The OCC will retain all proposals, or a copy of them, as part of the contract file for at least five (5) years. After this retention period, the OCC may return, destroy, or otherwise dispose of the proposals or the copies.

Waiver of Defects. The OCC has the right to waive any defects in any proposal or in the submission process followed by a prospective contractor. However, the OCC will only do so if it is in the best interest of the OCC and will not cause any material unfairness to other prospective contractors.

Amendments to Proposals. Amendments or withdrawals of proposals will be allowed if the amendment or withdrawal is received before the proposal due date. No amendment or withdrawals will be permitted after the due date, except as expressly authorized by the OCC.

Amendments to the RFP. If the OCC decides to revise this RFP, amendments will be made available to all prospective contractors. When the OCC makes amendments to the RFP after proposals have been submitted, the OCC will permit prospective contractors to withdraw or modify their proposals.

Contract. If this RFP results in a contract award, the contract will include by reference this RFP, written amendments to this RFP, the prospective contractor's proposal, and written, authorized amendments to the Contractor's proposal. It will also include any purchase orders and change orders issued under the Contract.

In addition, the prospective contractor will agree to abide by all laws, rules and directives of the State of Ohio, as they pertain to vendors doing business with the State of Ohio.

PART THREE: SCOPE OF WORK AND DELIVERABLES

This section describes the scope of work and what the selected contractor must deliver as part of the completed work (the "Deliverables") to meet the terms and conditions of the subsequent contract.

Scope of Work. The Independent Contractor will be fully responsible for the review, analysis, and evaluation of all materials filed by Duke Energy and any other parties in the proceedings relative to the company's Energy and Demand Forecast (OAC. 4901:5-5-05) and Resource Plans (OAC. 4901:5-5-06) filing. Through this evaluation process, the Independent Contractor will compare and contrast the filing with the appropriate chapters of the Ohio Administrative Code ("Rules") and the Ohio Revised Code. (See attached sections of the Revised Code and appropriate rules). The Independent Contractor will also provide limited technical support to OCC for other Ohio electric utility integrated resource plans.

The Independent Contractor will also be responsible for analysis and evaluation to determine whether the proposal is reasonable, is the least cost (subject to acceptable risk) option, and what other alternative options (including demand side) are available for meeting the generation needs. The Independent Contractor will be expected to bring to its analysis substantial experience in evaluating all issues related to integrated resource planning, growth and demand requirements and long-term forecasting.

The Independent Contractor's analysis and evaluation of these issues is expected to be conducted in conjunction primarily with the anticipated application of Duke Energy. A complete procedural schedule for these matters is not known at this time, but some key issues expected in this proceeding are discussed further in the attached press releases.

Work Requirements and Deliverables. The Independent Contractor shall undertake the following work and activities as requested and approved by OCC for the identification, analysis and development of all issues related to the integrated resource plan (primarily but not limited to the Energy and Demand Forecast [OAC. 4901:5-5-05] and Resource Plans [OAC. 4901:5-5-06] anticipated to be filed by Duke Energy. For other Ohio electric utility Integrated Resource Planning filings, no more than 20 hours of technical support will be made available upon OCC request.

1. Review and prepare an analysis and critique of the Company's integrated resource plan filing including a review of the Company's Application, work papers and supporting testimonies.

2. Review and prepare an analysis and critique of the Staff of the PUCO's report and other parties' comments on that report and any other parties' proposals.

3. Provide technical support on the issues relevant to integrated resource planning presented in the proceeding, including:

    a. Prepare discovery (interrogatories and requests for production of documents);
    b. Review responses to OCC's discovery; such review may require travel (e.g. Duke may make documents available in Columbus, Ohio and/or another location);
    c. Attend any depositions scheduled as required by OCC's Lead Attorney; such depositions may require travel;

d. As required by OCC, attendance at any depositions of the Independent Contractor conducted by the Company or other parties;

e. Review all discovery requests served upon the OCC by other parties and assist in preparing OCC's responses to such discovery.

4. Evaluate the plan to determine if it is the least cost option and if the proposed plan is reasonable.

5. Evaluate the Company's long-term forecasts of growth and demand.

6. Provide technical support, as identified by OCC's Lead Attorney, for the preparation of OCC pleadings (including comments on the Staff's Report) and litigation involved in the proceeding including an analysis of written and oral testimony of other witnesses (the Company, PUCO Staff and other parties) to assist with cross-examination.

7. Provide technical assistance needed for any pre-hearing or settlement conferences.

8. Based on resource planning related projections, answer the following questions:

   a. Is the proposed generation needed from a capacity and/or energy perspective based on an examination of their load forecast? The application has the burden to prove that the current resources are inadequate.
   b. Has Company contemplated other options? What alternative options (including Demand side) are available that are less costly and less risky which will still address the resource needs?

9. Prepare written, direct and, if needed, rebuttal testimony and presentation of that testimony at hearing. Testimony shall address:

   a. Whether the filing complies with the regulatory requirements of the Energy and Demand Forecast [OAC. 4901:5-5-05] and Resource Plans [OAC. 4901:5-5-06],

   b. The findings from section 8 above.

   c. A critique of the Company and other party and Commission staff positions,

   d. Recommendations on amending the Company's filing.

10. Review the information developed by and the testimony of OCC staff and of any co-consultants available to OCC in order to coordinate the OCC's development of issues in the proceeding, inasmuch as the subject matters addressed are related.

11. Provide technical assistance subsequent any hearing in order to prepare post-hearing briefs and evaluate issues for possible rehearing and/or appeals including, but not limited to, evaluation of those and related issues in the PUCO's Opinion and Order and, if requested, by OCC's Lead Attorney.

Information Included with the RFP. The following information is included for your information:

a. Two press clippings concerning Duke's consideration of a nuclear power plant in Ohio.
b. Ohio Revised Code Section 4928.143 Application for approval of electric security plan

c. Ohio Revised Code Section 4935.04 Energy Information and reports.
d. Ohio Revised Code Section 4909.15 Fixation of reasonable rate.
e. Ohio Administrative Code Chapters 4901:

    i. 1-35 Electric Security Plan and Market Rate Offer
    ii. 1-39 Energy Efficiency and Demand Reduction Benchmarks
    iii. 1-40 Alternative Energy Portfolio Standard
    iv. 1.41 Greenhouse Gas Reporting and Carbon Dioxide Control
    v. 5-3 Filing of Long-Term Forecast Reports; Fees
    vi. 5-5 Electric Utility Forecast Reports

PART FOUR: PROPOSAL REQUIREMENTS

Proposal Format. Each proposal must include sufficient data to allow the OCC to verify the total cost for the work and all of the prospective contractor's claims of meeting the RFP's requirements. These instructions describe the required format for a responsive proposal. The prospective contractor may include any additional information it believes is relevant.

1. **Contractor Profile.** Each proposal must include a general profile of the prospective contractor's relevant experience working on projects similar to this work. In the **Contractor Profile**, or in **Personnel Profile Summaries** (see below), details on prior and current similar and/or relevant work projects should be provided, including the scope of such work, clients, utility names and case numbers. While detail is generally preferred on a contractor's most recent work, <u>contractors are encouraged to provide detail on all relevant work in Ohio.</u>

   The profile must also include the prospective contractor's legal name, address, and telephone number; home office location; date established; ownership (such as public firm, partnership, or subsidiary); firm leadership (such as corporate officers or partners); total number of employees nationwide and in Ohio; the percentage of women employees nationwide and in Ohio; the percentage of minorities nationwide and in Ohio; number of employees to be engaged in tasks directly related to the work; and any other background information the prospective contractor believes would be useful during the proposal evaluation process. For any subcontractors included in your proposal, indicate whether they operate as an individual, partnership or corporation; if as a corporation, include the state in which they are incorporated. State whether they are licensed to operate in the State of Ohio. State the same employee information as noted above for the primary contractor (the percentage of woman and minorities nationwide and in Ohio).

2. **Work Plan.** The prospective contractor must fully describe its approach, methods, and specific work steps for doing the work and producing the **Work Requirements and Deliverables** set forth in Part Three of this RFP. The OCC encourages responses that demonstrate a thorough understanding of the nature of the work and what the Contractor must do to get the work done well. The prospective contractor must also provide a complete and detailed description of the way it will do the work that addresses the areas of concern identified below. The OCC seeks insightful responses that describe proven, state-of-the-art methods. Recommended solutions should demonstrate the prospective contractor's ability to quickly undertake and successfully complete the required tasks.

   In describing its work plan the prospective contractor should provide detail sufficient to demonstrate its understanding of (1) cost-of-service-study (if applicable), the distribution of the revenue requirement among the customer classes in general, (2) issues pertinent to the design of the rates proposed to be charged to residential customers of FirstEnergy Company, (3) potential and new ratemaking issues, (4) the current national and Ohio regulatory environment and (5) the mission of the OCC.

   The prospective contractor's work plan <u>**must clearly and specifically identify key personnel assignments and the number of hours by individual for each of the Work Requirements and Deliverables set forth in Part Three of this RFP**</u>.

3. **Personnel Profile Summaries.** Each prospective contractor must identify a project team that demonstrates a thorough understanding of the project and possesses the education and experience to support the successful completion of the project. Each proposal must include a profile and/or resume

for each key member of the proposed work team to demonstrate the competency of the project team personnel and include the following information:

- **Team Member Names**

- **Experience and Qualifications**. For each team member identify experience and qualifications relevant to this project, including testimonies previously presented. Identify which team members are expected to prepare the testimony to be filed in this docket.

- **Dates of Employment.** The length of time the team member performed relevant work requiring the necessary technical expertise.

- **Project Experience.** The work of the team member on projects of similar or greater size and scope, including projects in Ohio and/or for the OCC.

4. **References.** The prospective contractor must include three references for which the prospective contractor has successfully provided services on projects that were similar in their nature, size, and scope of work. These references must relate to work that was completed within the past five (5) years.

   Note: Each reference must be willing to discuss the prospective contractor's performance with an OCC representative.

5. **Cost Summary.** Each prospective **contractor must provide a cost summary table showing, for each project team member: (1) estimated hours, (2) hourly rates and (3) total estimated project costs for each of the Work Requirements and Deliverables** set forth in Part Three of this RFP.

   a) Executive Order 2009-07S, Implementing Additional Spending Control Strategies. Governor Ted Strickland's executive order states in part "...in this time when the state is struggling to maintain services critical to the health, safety and welfare of Ohio's citizens, the willingness of a vendor to negotiate a 15% or greater reduction in a contract's financial terms, while maintaining substantial equivalency of other terms, will be considered in the contract renewal decisions..."

      A documented fifteen percent reduction in an Independent Contractor's cost proposal, from their normal rates, will be looked at favorably.

   b) The OCC requires the inclusion of ALL expenses associated with this project within the hourly rates and hours used to determine the costs for the deliverables, thereby eliminating the need for expense billings. Items to be taken into consideration in determining the cost of each deliverable should include supplies and materials, transportation and per diems, copying and overnight mail charges, etc. The successful bidder will be responsible for direct payment to vendors for any requirements for overnight mail (including OCC to Contractor) and any "on-site" photocopying charges.

   c). **Contractor may invoice only for actual work performed and documented.**

   d.) The estimated budget for this project is $45,000.

6. **Subcontractors.** Acceptance by the Consumers' Counsel of a primary bidder's proposal does not necessarily require the Consumers' Counsel to accept the subcontractor(s) proposal proposed by the bidder. The Consumers' Counsel reserves the right to evaluate the qualifications of all sub-contractors proposed by the primary bidder.

7. The OCC will not be liable for any costs the prospective contractor does not identify in its proposal.

8. Submit a list of all Ohio public utilities for which you or your staff performed work in a professional capacity during the past three years.

9. Submit an original W9 form along with your response to this RFP so that, if a contract is awarded, the OCC can process any invoices submitted by your company. The Internet link to the form is: http://www.irs.gov/pub/irs-pdf/fw9.pdf. The form must be signed and dated.

10. Submit a statement along with your response to this RFP, affirming that you or members of your staff do not currently owe any money to the state of Ohio or have an unresolved finding for recovery from the Auditor of State.

11. **Declaration of Material Assistance/Non-Assistance.** If you will receive or have received in the aggregate an amount greater than $100,000 from the state of Ohio, you must complete a certification. You can complete the pre-certification process electronically by going to http://www.obg.ohio.gov.

12. **Campaign Contribution.** House Bill 694 requires that every contract for goods or services of more than $500 must contain a certification signed by the contract recipient certifying that the recipient is in compliance with Ohio Revised Code 3517.13. If awarded a contract, contractor will certify the following:

    "Contractor hereby certifies that all applicable parties listed in Division (I)(3) or (J)(3) of Ohio Revised Code Section 3517.13 are in full compliance with Divisions (I)(1) and (J)(1) of Ohio Revised Code Section 3517.13."

13. **Sweatshop Free.** By the signature affixed to this RFP, Independent Contractor certifies that all facilities used for the production of the supplies or performance of services offered in the bid/RFP are in compliance with applicable domestic labor, employment, health and safety, environmental and building laws. This certification applies to any and all suppliers and/or subcontractors used by the Independent Contractor in furnishing the supplies or services described in the bid/RFP and awarded to the Independent Contractor. If DAS receives a complaint alleging non-compliance with sweatshop free requirements, DAS may enlist the services of an independent monitor to investigate allegations of such non-compliance on the part of the Contractor, and sub-contractors or suppliers used by the Independent Contractor in performance on the Contract. If allegations are proven to be accurate, the Contractor will be advised by DAS of the next course of action to resolve the complaint and the Contractor will be responsible for any costs associated with the investigation. Items that will be considered in an investigation include, but are not limited to, standards for wages, occupational safety, and work hours.

    For more information please refer to http://www.obm.ohio.gov.

PART FIVE: EVALUATION OF PROPOSALS

Evaluation of Proposals. Generally, the evaluation process may consist of up to four distinct phases:

1. The Initial Review of all proposals for defects
2. The Evaluation of the proposals by the Evaluation Committee
3. Request for More Information (Interviews, Presentations, and Demonstrations)
4. Negotiations

It is within the purview of the OCC Evaluation Committee ("Committee") to decide whether phases three and four are necessary.

Rejection of Proposals. The OCC may reject any proposal that is not in the required format, does not address all the requirements of this RFP, or that the OCC believes is excessive in price or otherwise not in the best interest of the OCC to consider or to accept. In addition, the OCC may cancel this RFP, reject all the proposals, and seek to do the work through a new RFP or other means.

Clarifications: During the evaluation process, clarifications may be requested from any prospective contractor under active consideration and the clarification may give any prospective contractor the opportunity to correct defects in its proposal. This may be done in cases where doing so would not result in an unfair advantage for the prospective contractor and the clarification is in the best interest of the OCC.

1. **Initial Review:** The proposals will be reviewed for their timeliness, format, and completeness. Any late, incomplete, or incorrectly formatted proposals may be rejected. Likewise, any defects may be waived or a prospective contractor may be allowed to submit a correction.

   If a late proposal is received, it will not be opened unless the prospective contractor has received prior OCC approval for a late proposal for good cause shown.

   All timely, complete, and properly formatted proposals will be forwarded to the Evaluation Committee.

2. **Committee Evaluation of the Proposals:** The Committee will evaluate each proposal forwarded to it. The Committee may also have the proposals or portions of them reviewed and evaluated by independent third parties or other OCC personnel with technical or professional experience that relates to the work or to the criteria used in the evaluation process. The Committee may adopt or reject any recommendations it receives from such reviews and evaluations. At any time during this phase, the Committee may ask a prospective contractor to correct, revise, or clarify any portions of its proposal.

Contract Award. The OCC plans to tentatively award the Contract for the work on **April 23, 2010**. The OCC reserves the right to change the contract award date if it becomes necessary. The contract will be awarded to the contractor that demonstrates a clear understanding of OCC's expectations; can complete the scope of work and deliverables within the designated timeframe, and at the lowest or competitive cost

2 NEWS ARTICLES

(ARTICLE 1)
NEWS.CINCINNATI.COM
OHIO DUKE CONSIDERING NUCLEAR PLANT

(ARTICLE 2)
WSJ.COM
DUKE WEIGHS NUCLEAR PLANT

Cincinnati.Com

February 7, 2010

Ohio, Duke considering nuclear plant

By Mike Boyer
mboyer@enquirer.com

President Barack Obama's call for a new generation of nuclear power plants could weigh on decisions about a possible new nuclear facility at the former uranium processing reservation in Piketon.

But nobody expects any significant activity soon.

It's been more than six months since Ohio Gov. Ted Strickland, U.S. Sen. George Voinovich, top officials from Duke Energy and other utility companies announced formation of the Southern Ohio Clean Energy Park Alliance.

The informal alliance was formed to explore development of a 1,600-megawatt nuclear generating plant at a "clean energy park," which could cost more than $10 billion, take more than a decade to build and create thousands of jobs.

"We are still in the initial stages of this project. We have a lengthy, methodical process we go through," said Sally Thelen, a Duke spokeswoman in Cincinnati.

The proposed Piketon facility, located about 95 miles east of Cincinnati, would be Ohio's third nuclear power plant and the first since the Perry nuclear plant in Lake County came on line in 1987.

Duke, which is looking for cleaner sources of electric power, isn't committed to building the plant but is seeking several million dollars in Department of Energy funding to study feasibility of the Piketon project and to initiate the lengthy site permitting process.

Obama singled out nuclear power in his State of the Union address, saying new nuke plants would create more clean-energy jobs.

The 104 nuclear reactors in operation in 31 states provide only 20 percent of the nation's electricity. But they are responsible for 70 percent of the power from pollution-free sources, including wind, solar and hydroelectric plants, advocates say.

Duke said it is continuing to refine its timetable for the Piketon project and is talking to other utilities about participating in the project. The Southern Ohio Clean Energy Park Alliance also includes French-based nuclear plant builder Areva Inc. and USEC Inc., which manages the 3,700-acre site in Pike County.

The Energy Department said it is reviewing the proposal but wouldn't comment further.

In the complex and costly world of nuclear power, such lengthy timetables aren't unusual.

For example, Duke said, planning for its William States Lee III nuclear generating station, a 2,234-megawatt plant in Cherokee, S.C., started in 2005. A license application to the Nuclear Regulatory Commission wasn't filed until 2007.

"We likely won't hear on our license acceptance or rejection until 2012-2013," Thelen said.

The Obama administration wants to triple the Energy Department's loan guarantee program for nuclear power to $54 billion, enough to support seven to 10 new reactors.

If Duke does move forward, it could apply for some of the loan guarantees.

THE WALL STREET JOURNAL.
WSJ.com

BUSINESS | JUNE 19, 2009

Duke Weighs Nuclear Plant

By REBECCA SMITH and MARK PETERS

Duke Energy Corp. said it may seek permission to build a nuclear plant on a 3,700-acre federally controlled site in Ohio formerly used for a uranium enrichment facility. It would partner with French-based reactor vendor Areva SA and nuclear developer UniStar Nuclear Energy.

Duke's proposal is unusual because the company already is attempting to build two nuclear reactors at a site it owns in South Carolina using Westinghouse Electric Co. technology. That technology, called the AP1000, has been approved for U.S. use. Experts expect utilities to stick to a single technology type for all their reactors and not complicate their task by building units with different designs. No other company has proposed building different reactor technologies in different states.

The partners said they may seek an early site permit from the Nuclear Regulatory Commission in a process that would assess suitability of the site at Piketon, Ohio, for nuclear-power development.

An application for a nuclear construction and operating license would follow, likely by 2010 or 2011, when the reactor design developed by Areva, called the US-EPR, is expected to be approved for U.S. use by the NRC.

Jim Rogers, Duke's chief executive, said his firm operates two reactor types at its seven operating reactors and isn't deterred by having a technology mix. He said Areva's design has certain advantages, in his opinion, including better resistance to an attack.

Ann Lauvergeon, chief executive of Areva, said Duke's selection of the design by Westinghouse, now majority owned by Japan's Toshiba Corp., was "the right choice at the time" but that the Areva reactor is a "fortress" and already is under construction in three nations -- Finland, France and China. She also said that at 1,600 megawatts it is larger than the Westinghouse reactor, which is about 1,150 megawatts.

Ohio obtains more than 85% of its electricity from coal incineration, one of the highest amounts of any state. Looming federal carbon legislation could raise the cost of coal-based electricity in coming years, pushing utility companies like Duke to explore lower-carbon options.

Ohio Gov. Ted Strickland praised the proposal, but public opposition could arise. There also could be a legal problem. An Ohio law requires utilities to prove new plants are needed and that the technology proposed is the least costly option. "It's a very dicey proposition to propose nuclear power, if they want Ohio consumers to bear the cost," said Janine Migden Ostrander, Ohio's consumer counsel.

Mr. Rogers said Duke will seek to make the Pike County plant a regional power plant, bringing in other utilities as partners. Ohio has had a checkered history with nuclear power. One nuclear project in Moscow, Ohio, begun by Cinergy, which merged with Duke three years ago, never was brought into service, despite the expenditure of billions of dollars. In the mid-1980s, it was converted into a coal unit at additional cost.

Write to Rebecca Smith at rebecca.smith@wsj.com and Mark Peters at mark.peters@dowjones.com

Printed in The Wall Street Journal, page B2

ORC 4928.143

APPLICATION FOR APPROVAL OF ELECTRIC SECURITY PLAN – TESTING

4928.143 Application for approval of electric security plan - testing.

(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.

(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code; and provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(C)(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

(2)(a) If the commission modifies and approves an application under division (C)(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division (C)(2)(a) of this section or if the commission disapproves an application under division (C)(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.

(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division (C) of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division (C) of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141, division (B) of section 4928.64, or division (A) of section 4928.66 of the Revised Code.

(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

Effective Date: 2008 SB221 07-31-2008

ORC 4935.04

ENERGY INFORMATION AND REPORTS

4935.04 Energy information and reports.

(A) As used in this chapter:

(1) "Major utility facility" means:

(a) An electric transmission line and associated facilities of a design capacity of one hundred twenty-five kilovolts or more;

(b) A gas or natural gas transmission line and associated facilities designed for, or capable of, transporting gas or natural gas at pressures in excess of one hundred twenty-five pounds per square inch.

"Major utility facility" does not include electric, gas, or natural gas distributing lines and gas or natural gas gathering lines and associated facilities as defined by the public utilities commission; facilities owned or operated by industrial firms, persons, or institutions that produce or transmit gas or natural gas, or electricity primarily for their own use or as a byproduct of their operations; gas or natural gas transmission lines and associated facilities over which an agency of the United States has certificate jurisdiction; facilities owned or operated by a person furnishing gas or natural gas directly to fifteen thousand or fewer customers within this state.

(2) "Person" has the meaning set forth in section 4906.01 of the Revised Code.

(B) Each person owning or operating a gas or natural gas transmission line and associated facilities within this state over which an agency of the United States has certificate jurisdiction shall furnish to the commission a copy of the energy information filed by the person with that agency of the United States.

(C) Each person owning or operating a major utility facility within this state, or furnishing gas, natural gas, or electricity directly to more than fifteen thousand customers within this state annually shall furnish a report to the commission for its review. The report shall be termed the long-term forecast report and shall contain:

(1) A year-by-year, ten-year forecast of annual energy demand, peak load, reserves, and a general description of the resource plan to meet demand;

(2) A range of projected loads during the period;

(3) A description of major utility facilities planned to be added or taken out of service in the next ten years, including, to the extent the information is available, prospective sites for transmission line locations;

(4) For gas and natural gas, a projection of anticipated supply, supply prices, and sources of supply over the forecast period;

(5) A description of proposed changes in the transmission system planned for the next five years;

(6) A month-by-month forecast of both energy demand and peak load for electric utilities, and gas sendout for gas and natural gas utilities, for the next two years. The report shall describe the major utility facilities that, in the judgment of such person, will be required to supply system demands during the forecast period. The report from a gas or natural gas utility shall cover the ten- and five-year periods next succeeding the date of the report, and the report from an electric utility shall cover the twenty-, ten-, and five-year periods next succeeding the date of the report. Each report shall be made available to the public and furnished upon request to municipal corporations and governmental agencies charged with the duty of protecting the environment or of planning land use. The report shall be in such form and shall contain such information as may be prescribed by the commission. Each person not owning or operating a major utility facility within this state and serving fifteen thousand or fewer gas or natural gas, or electric customers within this state shall furnish such information as the commission requires.

(D) The commission shall:

(1) Review and comment on the reports filed under division (C) of this section, and make the information contained in the reports readily available to the public and other interested government agencies;

(2) Compile and publish each year the general locations of proposed and existing transmission line routes within its jurisdiction as identified in the reports filed under division (C) of this section, identifying the general location of such sites and routes and the approximate year when construction is expected to commence, and to make such information readily available to the public, to each newspaper of daily or weekly circulation within the area affected by the proposed site and route, and to interested federal,

state, and local agencies;

(3) Hold a public hearing:

(a) On the first long-term forecast report filed after January 11, 1983;

(b) At least once in every five years, on the latest report furnished by any person subject to this section;

(c) On the latest report furnished by any person subject to this section if the report contains a substantial change from the preceding report furnished by that person. "Substantial change" includes, but is not limited to:

(i) A change in forecasted peak loads or energy consumption over the forecast period of greater than an average of one-half of one per cent per year;

(ii) Demonstration of good cause to the commission by an interested party. The commission shall fix a time for the hearing, which shall be not later than ninety days after the report is filed, and publish notice of the date, time of day, and location of the hearing in a newspaper of general circulation in each county in which the person furnishing the report has or intends to locate a major utility facility and will provide service during the period covered by the report. The notice shall be published not less than fifteen nor more than thirty days before the hearing and shall state the matters to be considered. Absent a showing of good cause, the commission shall not hold hearings under division (D)(3) of this section with respect to persons who, as the primary purpose of their business, furnish gas or natural gas, or electricity directly to fifteen thousand or fewer customers within this state solely for direct consumption by those customers.

(4) Require such information from persons subject to its jurisdiction as necessary to assist in the conduct of hearings and any investigation or studies it may undertake;

(5) Conduct any studies or investigations that are necessary or appropriate to carry out its responsibilities under this section.

(E)(1) The scope of the hearing held under division (D)(3) of this section shall be limited to issues relating to forecasting. The power siting board, the office of consumers' counsel, and all other persons having an interest in the proceedings shall be afforded the opportunity to be heard and to be represented by counsel. The commission may adjourn the hearing from time to time.

(2) The hearing shall include, but not be limited to, a review of:

(a) The projected loads and energy requirements for each year of the period;

(b) The estimated installed capacity and supplies to meet the projected load requirements.

(F) Based upon the report furnished pursuant to division (C) of this section and the hearing record, the commission, within ninety days from the close of the record in the hearing, shall determine if:

(1) All information relating to current activities, facilities agreements, and published energy policies of the state has been completely and accurately represented;

(2) The load requirements are based on substantially accurate historical information and adequate methodology;

(3) The forecasting methods consider the relationships between price and energy consumption;

(4) The report identifies and projects reductions in energy demands due to energy conservation measures in the industrial, commercial, residential, transportation, and energy production sectors in the service area;

(5) Utility company forecasts of loads and resources are reasonable in relation to population growth estimates made by state and federal agencies, transportation, and economic development plans and forecasts, and make recommendations where possible for necessary and reasonable alternatives to meet forecasted electric power demand;

(6) The report considers plans for expansion of the regional power grid and the planned facilities of other utilities in the state;

(7) All assumptions made in the forecast are reasonable and adequately documented.

(G) The commission shall adopt rules under section 111.15 of the Revised Code to establish criteria for evaluating the long-term forecasts of needs for gas and electric transmission service, to conduct hearings held under this section, to establish reasonable fees to defray the direct cost of the hearings and the review process, and such other rules as are necessary and convenient to implement this section.

(H) The hearing record produced under this section and the determinations of the commission shall be introduced into evidence and shall be considered in determining the basis of need for power siting board deliberations under division (A)(1) of section 4906.10 of the Revised Code. The hearing record produced under this section shall be introduced into evidence and shall be considered by the public utilities commission in its initiation of programs, examinations, and findings under section 4905.70 of the Revised Code, and shall be considered in the commission's determinations with respect to the establishment of just and reasonable rates under section 4909.15 of the Revised Code and financing utility facilities and authorizing issuance of all securities under sections 4905.40, 4905.401, 4905.41, and 4905.42 of the Revised Code. The forecast findings also shall serve as the basis for all other energy planning and development activities of the state government where electric and gas data are required.

(I)(1) No court other than the supreme court shall have power to review, suspend, or delay any determination made by the commission under this section, or enjoin, restrain, or interfere with the commission in the performance of official duties. A writ of mandamus shall not be issued against the commission by any court other than the supreme court.

(2) A final determination made by the commission shall be reversed, vacated, or modified by the supreme court on appeal, if, upon consideration of the record, such court is of the opinion that such determination was unreasonable or unlawful. The proceeding to obtain such reversal, vacation, or modification shall be by notice of appeal, filed with the commission by any party to the proceeding before it, against the commission, setting forth the determination appealed from and errors complained of. The notice of appeal shall be served, unless waived, upon the commission by leaving a copy at the office of the chairperson of the commission at Columbus. The court may permit an interested party to intervene by cross-appeal.

(3) No proceeding to reverse, vacate, or modify a determination of the commission is commenced unless the notice of appeal is filed within sixty days after the date of the determination.

Effective Date: 01-01-2001

ORC 4909.15

FIXATION OF REASONABLE RATE

4909.15 Fixation of reasonable rate.

(A) The public utilities commission, when fixing and determining just and reasonable rates, fares, tolls, rentals, and charges, shall determine:

(1) The valuation as of the date certain of the property of the public utility used and useful in rendering the public utility service for which rates are to be fixed and determined. The valuation so determined shall be the total value as set forth in division (J) of section 4909.05 of the Revised Code, and a reasonable allowance for materials and supplies and cash working capital, as determined by the commission. The commission, in its discretion, may include in the valuation a reasonable allowance for construction work in progress but, in no event, may such an allowance be made by the commission until it has determined that the particular construction project is at least seventy-five per cent complete. In determining the percentage completion of a particular construction project, the commission shall consider, among other relevant criteria, the per cent of time elapsed in construction; the per cent of construction funds, excluding allowance for funds used during construction, expended, or obligated to such construction funds budgeted where all such funds are adjusted to reflect current purchasing power; and any physical inspection performed by or on behalf of any party, including the commission's staff. A reasonable allowance for construction work in progress shall not exceed ten per cent of the total valuation as stated in this division, not including such allowance for construction work in progress. Where the commission permits an allowance for construction work in progress, the dollar value of the project or portion thereof included in the valuation as construction work in progress shall not be included in the valuation as plant in service until such time as the total revenue effect of the construction work in progress allowance is offset by the total revenue effect of the plant in service exclusion. Carrying charges calculated in a manner similar to allowance for funds used during construction shall accrue on that portion of the project in service but not reflected in rates as plant in service, and such accrued carrying charges shall be included in the valuation of the property at the conclusion of the offset period for purposes of division (J) of section 4909.05 of the Revised Code.

From and after April 10, 1985, no allowance for construction work in progress as it relates to a particular construction project shall be reflected in rates for a period exceeding forty-eight consecutive months commencing on the date the initial rates reflecting such allowance become effective, except as otherwise provided in this division. The applicable maximum period in rates for an allowance for construction work in progress as it relates to a particular construction project shall be tolled if, and to the extent, a delay in the in-service date of the project is caused by the action or inaction of any federal, state, county, or municipal agency having jurisdiction, where such action or inaction relates to a change in a rule, standard, or approval of such agency, and where such action or inaction is not the result of the failure of the utility to reasonably endeavor to comply with any rule, standard, or approval prior to such change. In the event that such period expires before the project goes into service, the commission shall exclude, from the date of expiration, the allowance for the project as construction work in progress from rates, except that the commission may extend the expiration date up to twelve months for good cause shown. In the event that a utility has permanently canceled, abandoned, or terminated construction of a project for which it was previously permitted a construction work in progress allowance, the commission immediately shall exclude the allowance for the project from the valuation. In the event that a construction work in progress project previously included in the valuation is removed from the valuation pursuant to this division, any revenues collected by the utility from its customers after April 10, 1985, that resulted from such prior inclusion shall be offset against future revenues over the same period of time as the project was included in the valuation as construction work in progress. The total revenue effect of such offset shall not exceed the total revenues previously collected. In no event shall the total revenue effect of any offset or offsets provided under division (A)(1) of this section exceed the total revenue effect of any construction work in progress allowance.

(2) A fair and reasonable rate of return to the utility on the valuation as determined in division (A)(1) of this section;

(3) The dollar annual return to which the utility is entitled by applying the fair and reasonable rate of return as determined under division (A)(2) of this

section to the valuation of the utility determined under division (A)(1) of this section;

(4) The cost to the utility of rendering the public utility service for the test period less the total of any interest on cash or credit refunds paid, pursuant to section 4909.42 of the Revised Code, by the utility during the test period.

(a) Federal, state, and local taxes imposed on or measured by net income may, in the discretion of the commission, be computed by the normalization method of accounting, provided the utility maintains accounting reserves that reflect differences between taxes actually payable and taxes on a normalized basis, provided that no determination as to the treatment in the rate-making process of such taxes shall be made that will result in loss of any tax depreciation or other tax benefit to which the utility would otherwise be entitled, and further provided that such tax benefit as redounds to the utility as a result of such a computation may not be retained by the company, used to fund any dividend or distribution, or utilized for any purpose other than the defrayal of the operating expenses of the utility and the defrayal of the expenses of the utility in connection with construction work.

(b) The amount of any tax credits granted to an electric light company under section 5727.391 of the Revised Code for Ohio coal burned prior to January 1, 2000, shall not be retained by the company, used to fund any dividend or distribution, or utilized for any purposes other than the defrayal of the allowable operating expenses of the company and the defrayal of the allowable expenses of the company in connection with the installation, acquisition, construction, or use of a compliance facility. The amount of the tax credits granted to an electric light company under that section for Ohio coal burned prior to January 1, 2000, shall be returned to its customers within three years after initially claiming the credit through an offset to the company's rates or fuel component, as determined by the commission, as set forth in schedules filed by the company under section 4905.30 of the Revised Code. As used in division (A)(4)(c) of this section, "compliance facility" has the same meaning as in section 5727.391 of the Revised Code.

(B) The commission shall compute the gross annual revenues to which the utility is entitled by adding the dollar amount of return under division (A)(3) of this section to the cost of rendering the public utility service for the test period under division (A)(4) of this section.

(C) The test period, unless otherwise ordered by the commission, shall be the twelve-month period beginning six months prior to the date the application is filed and ending six months subsequent to that date. In no event shall the test period end more than nine months subsequent to the date the application is filed. The revenues and expenses of the utility shall be determined during the test period. The date certain shall be not later than the date of filing.

(D) When the commission is of the opinion, after hearing and after making the determinations under divisions (A) and (B) of this section, that any rate, fare, charge, toll, rental, schedule, classification, or service, or any joint rate, fare, charge, toll, rental, schedule, classification, or service rendered, charged, demanded, exacted, or proposed to be rendered, charged, demanded, or exacted, is, or will be, unjust, unreasonable, unjustly discriminatory, unjustly preferential, or in violation of law, that the service is, or will be, inadequate, or that the maximum rates, charges, tolls, or rentals chargeable by any such public utility are insufficient to yield reasonable compensation for the service rendered, and are unjust and unreasonable, the commission shall:

(1) With due regard among other things to the value of all property of the public utility actually used and useful for the convenience of the public as determined under division (A)(1) of this section, excluding from such value the value of any franchise or right to own, operate, or enjoy the same in excess of the amount, exclusive of any tax or annual charge, actually paid to any political subdivision of the state or county, as the consideration for the grant of such franchise or right, and excluding any value added to such property by reason of a monopoly or merger, with due regard in determining the dollar annual return under division (A)(3) of this section to the necessity of making reservation out of the income for surplus, depreciation, and contingencies, and;

(2) With due regard to all such other matters as are proper, according to the facts in each case,

(a) Including a fair and reasonable rate of return determined by the commission with reference to a cost of debt equal to the actual embedded cost of debt of such public utility,

(b) But not including the portion of any periodic rental or use payments representing that cost of property that is included in the valuation report under divisions (F) and (G) of section 4909.05 of the Revised Code, fix and determine the just and reasonable rate, fare, charge, toll, rental, or service to be rendered, charged, demanded, exacted, or collected for the performance or rendition of the service that will provide the public utility the allowable gross annual revenues under division (B) of this section, and order such just and reasonable rate, fare, charge, toll, rental, or service to be substituted for the existing one. After such determination and order no change in the rate, fare, toll, charge, rental, schedule, classification, or service shall be made, rendered, charged, demanded, exacted, or changed by such public utility without the order of the commission, and any other rate, fare, toll, charge, rental, classification, or service is prohibited.

(E) Upon application of any person or any public utility, and after notice to the parties in interest and opportunity to be heard as provided in Chapters 4901., 4903., 4905., 4907., 4909., 4921., and 4923. of the Revised Code for other hearings, has been given, the commission may rescind, alter, or amend an order fixing any rate, fare, toll, charge, rental, classification, or service, or any other order made by the commission. Certified copies of such orders shall be served and take effect as provided for original orders.

Effective Date: 11-24-1999

ORC 4901:1-35

TERMINOLOGY DEFINITIONS

Chapter 4901:1-35

4901:1-35-01 Definitions.

(A) "Application" means an application for standard service offer pursuant to this chapter.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Competitive bidding process" means a bidding process established pursuant to section 4928.142 of the Revised Code.

(D) "Dynamic retail pricing" means a retail rate design which includes prices that can change based on changes in wholesale electricity prices, power system conditions, or the marginal cost of providing electric service.

(E) "Electric utility" shall have the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(F) "Electric security plan" means an electric utility plan for the supply and pricing of electric generation service including other related matters pursuant to section 4928.143 of the Revised Code.

(G) "First application for a market rate offer" means the application filed under section 4928.142 of the Revised Code by an electric utility that has not previously implemented an approved market-rate offer.

(H) "Market development period" shall have the meaning set forth in division (A)(17) of section 4928.01 of the Revised Code.

(I) "Market-rate offer" means an electric utility plan for the supply and pricing of electric generation service pursuant to section 4928.142 of the Revised Code.

(J) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(K) "Rate plan" means an electric utility's standard service offer approved by the commission prior to January 1, 2009, that established rates for electric service at the expiration of an electric utility's market development period.

(L) "Standard service offer" means an electric utility offer to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

(M) "Staff" means the staff of the commission or its authorized representatives.

(N) "Time differentiated pricing" means a retail rate design which includes differing prices based upon the time that electricity is used in order to reflect differences in expected costs or wholesale electricity prices in different time periods.

Replaces: 4901:1-35-01
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R.C. 119.032 review date: 9/30/12
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Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.14, 4928.141, 4928.142, 4928.143
Prior effective date: 5/27/04

4901:1-35-02 Purpose and scope.

(A) Pursuant to division (A) of section 4928.141 of the Revised Code, beginning January 1, 2009, each electric utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Pursuant to this chapter, an electric utility shall file an application for commission approval of an SSO. Such application shall be in the form of an electric security plan or market rate offer pursuant to sections 4928.142 and 4928.143 of the Revised Code. The purpose of this chapter is to establish rules for the form and process under which an electric utility shall file an application for an SSO and the commission's review of that application.

(B) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

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Prior effective date: 5/27/04

4901:1-35-03 Filing and contents of applications.

Each electric utility in this state filing an application for a standard service offer (SSO) in the form of an electric security plan (ESP), a market-rate offer (MRO), or both, shall comply with the requirements set forth in this rule.

(A) SSO applications shall be case captioned as (XX-XXX-EL-SSO). Twenty copies plus an original of the application shall be filed. The application must include a complete set of direct testimony of the electric utility personnel or other expert witnesses. This testimony shall be in question and answer format and shall be in support of the electric utility's proposed application. This testimony shall fully support all schedules and significant issues identified by the electric utility.

(B) An SSO application that contains a proposal for an MRO shall comply with the requirements set forth below.

(1) The following electric utility requirements are to be demonstrated in a separate section of the standard service offer SSO application proposing a market-rate offer MRO:

(a) The electric utility shall establish one of the following: that it, or its transmission affiliate, belongs to at least one regional transmission organization (RTO) that has been approved by the federal energy regulatory commission; or, if the electric utility or its transmission affiliate does not belong to an RTO, then the electric utility shall demonstrate that alternative conditions exist with regard to the transmission system, which include non-pancaked rates, open access by generation suppliers, and full interconnection with the distribution grid.

(b) The electric utility shall establish one of the following: its RTO retains an independent market-monitor function and has the ability to identify any potential for a market participant or the electric utility to exercise market power in any energy, capacity, and/or ancillary service markets by virtue of access to the RTO and the market participant's data and personnel and has the ability to effectively mitigate the conduct of the market participants so as to prevent or preclude the exercise of such market power by any market participant or the electric utility; or the electric utility shall demonstrate that an equivalent function exists which can monitor, identify, and mitigate conduct associated with the exercise of such market power.

(c) The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any energy product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the competitive bidding process (CBP) is publicly available. The information may be offered through a pay subscription service, but the pay subscription service shall be available under standard pricing, terms, and conditions to any person requesting a subscription. The published information shall be representative of prices and changes in prices in the electric utility's electricity market, and shall identify pricing of on-peak and off-peak energy products that represent contracts for delivery, encompassing a time frame beginning at least two years from the date of the publication. The published information shall be updated on at least a monthly basis.

(2) Prior to establishing an MRO under division (A) of section 4928.142 of the Revised Code, an electric utility shall file a plan for a CBP with the commission. The electric utility shall provide justification of its proposed CBP plan, considering alternative possible methods of procurement. Each CBP plan that is to be used to establish an MRO shall include the following:

(a) A complete description of the CBP plan and testimony explaining and supporting each aspect of the CBP plan. The description shall include a discussion of any relationship between the wholesale procurement process and the retail rate design that may be proposed in the CBP plan. The description shall include a discussion of alternative methods of procurement that were considered and the rationale for selection of the CBP plan being presented. The description shall also include an explanation of every proposed non-avoidable charge, if any, and why the charge is proposed to be non-avoidable.

(b) Pro forma financial projections of the effect of the CBP plan's implementation, including implementation of division (D) of section 4928.142 of the Revised Code, upon generation, transmission, and distribution of the electric utility, for the duration of the CBP plan.

(c) Projected generation, transmission, and distribution rate impacts by customer class and rate schedules for the duration of the CBP plan. The electric utility shall clearly indicate how projected bid clearing prices used for this purpose were derived.

(d) Detailed descriptions of how the CBP plan ensures an open, fair, and transparent competitive solicitation that is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code.

(e) Detailed descriptions of the customer load(s) to be served by the winning bidder(s), and any known factors that may affect such customer loads. The descriptions shall include, but not be limited to, load subdivisions defined for bidding purposes, load and rate class descriptions, customer load profiles that include historical hourly load data for each load and rate class for at least the two most recent years, applicable tariffs, historical shopping data, and plans for meeting targets pertaining to load reductions, energy efficiency, renewable energy, advanced energy, and advanced energy technologies. If customers will be served pursuant to time-differentiated or dynamic pricing, the descriptions shall include a summary of available data regarding the price elasticity of the load. Any fixed load provides to be served by winning bidder(s) shall be described.

(f) Detailed descriptions of the generation and related services that are to be provided by the winning bidder(s). The descriptions shall include, at a minimum, capacity, energy, transmission, ancillary and resource adequacy services, and the term during which generation and related services are to be provided. The descriptions shall clearly indicate which services are to be provided by the winning bidder(s) and which services are to be provided by the electric utility.

(g) Draft copies of all forms, contracts, or agreements that must be executed during or upon completion of the CBP.

(h) A clear description of the proposed methodology by which all bids would be evaluated, in sufficient detail so that bidders and other observers can ascertain the evaluated result of any bids or potential bids.

(i) The CBP plan shall include a discussion of time-differentiated pricing, dynamic retail pricing, and other alternative retail rate options that were considered in the development of the CBP plan. A clear description of the rate structure ultimately chosen by the electric utility, the electric utility's rationale for selection of the chosen rate structure, and the methodology by which the electric utility proposes to convert the winning bid(s) to retail rates of the electric utility shall be included in the CBP plan.

(j) The first application for a market rate offer by an electric utility that, as of July 31, 2008, directly owned, in whole or in part, operating electric generation facilities that had been used and useful in this state shall include a description of the electric utility's proposed blending of the CBP rates for the first five years of the market rate offer pursuant to division (D) of section 4928.142 of the Revised Code. The proposed blending shall show the generation service price(s) that will be blended with the CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending will be accomplished. The proposed blending shall show all adjustments, to be made on a quarterly basis, included in the generation service price(s) that the electric utility proposes for changes in costs of fuel, purchased power, portfolio requirements, and environmental compliance incurred during the blending period. The electric utility shall provide its best current estimate of anticipated adjustment amounts for the duration of the blending period, and compare the projected adjusted generation service prices under the CBP plan to the projected adjusted generation service prices under its proposed electric security plan.

(k) The electric utility's application to establish a CBP shall include such information as necessary to demonstrate whether or not, as of July 31, 2008, the electric utility directly owned, in whole or in part, operating electric generation facilities that had been used and useful in the state of Ohio.

(l) The CBP plan shall provide for funding of a consultant that may be selected by the commission to assess and report to the commission on the design of the solicitation, the oversight of the bidding process, the clarity of the product definition, the fairness, openness, and transparency of the solicitation and bidding process, the market factors that could affect the solicitation, and other relevant criteria as directed by the commission. Recovery of the cost of such consultant(s) may be included by the electric utility in its CBP plan.

(m) The CBP plan shall include a discussion of generation service procurement options that were considered in development of the CBP plan, including but not limited to, portfolio approaches, staggered procurement, forward procurement, electric utility participation in day-ahead and/or real-time balancing markets, and spot market purchases and sales. The CBP plan shall also include the rationale for selection of any or all of the procurement options.

(n) The electric utility shall show, as a part of its CBP plan, any relationship between the CBP plan and the electric utility's plans to comply with alternative energy portfolio requirements of section 4928.64 of the Revised Code, and energy efficiency requirements and peak demand reduction requirements of section 4928.66 of the Revised Code. The initial filing of a CBP plan shall include a detailed account of how the plan is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include a discussion of how the state policy continues to be advanced by the plan.

(o) An explanation of known and anticipated obstacles that may create difficulties or barriers for the adoption of the proposed bidding process.

(3) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(4) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I) and (K) of section 4928.20 of the Revised Code.

(C) An SSO application that contains a proposal for an ESP shall comply with the requirements set forth below.

(1) A complete description of the ESP and testimony explaining and supporting each aspect of the ESP.

(2) Pro forma financial projections of the effect of the ESP's implementation upon the electric utility for the duration of the ESP, together with testimony and work papers sufficient to provide an understanding of the assumptions made and methodologies used in deriving the pro forma projections.

(3) Projected rate impacts by customer class/rate schedules for the duration of the ESP, including post-ESP impacts of deferrals, if any.

(4) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including, but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(5) Division (A)(3) of section 4928.31 of the Revised Code required each electric utility to file an operational support plan as a part of its electric transition plan. Each electric utility shall provide a statement as to whether its operational support plan has been implemented and whether there are any outstanding problems with the implementation.

(6) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I), (J), and (K) of section 4928.20 of the Revised Code.

(7) A description of the effect on large-scale governmental aggregation of any unavoidable generation charge proposed to be established in the ESP.

(8) The initial filing for an ESP shall include a detailed account of how the ESP is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include how the state policy is advanced by the ESP.

(9) Specific information

Division (B)(2) of section 4928.143 of the Revised Code authorizes the provision or inclusion in an ESP of a number of features or mechanisms. To the extent that an electric utility includes any of these features in its ESP, it shall file the corresponding information in its application.

(a) Division (B)(2)(a) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the automatic recovery of fuel, purchased power, and certain other specified costs. An application including such provisions shall include, at a minimum, the information described below:

(i) The type of cost the electric utility is seeking recovery for under division (B)(2) of section 4928.143 of the Revised Code including a summary and detailed description of such cost. The description shall include the plant(s) that the cost pertains to as well as a narrative pertaining to the electric utility's procurement policies and procedures regarding such cost.

(ii) The electric utility shall include in the application any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales and profits from resold coal contracts.

(iii) The specific means by which these costs will be recovered by the electric utility. In this specification, the electric utility must clearly distinguish whether these costs are to be recovered from all distribution customers or only from the customers taking service under the ESP.

(iv) A complete set of work papers supporting the cost must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative and other support of assumptions made in completing the work papers.

(b) Divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, authorize an electric utility to include unavoidable surcharges for construction, generation, or environmental expenditures for electric generation facilities owned or operated by the electric utility. Any plan which seeks to impose surcharge under these provisions shall include the following sections, as appropriate:

(i) The application must include a description of the projected costs of the proposed facility. The need for the proposed facility must have already been reviewed and determined by the commission through an integrated resource planning process filed pursuant to rule 4901:5-5-05 of the Administrative Code.

(ii) The application must also include a proposed process, subject to modification and approval by the commission, for the competitive bidding of the construction of the facility unless the commission has previously approved a process for competitive bidding, which would be applicable to that specific facility.

(iii) An application which provides for the recovery of a reasonable allowance for construction work in progress shall include a detailed description of the actual costs as of a date certain for which the applicant seeks recovery, a detailed description of the impact upon rates of the proposed surcharge, and a demonstration that such a construction work in progress allowance is consistent with the applicable limitations of division (A) of section 4909.15 of the Revised Code.

(iv) An application which provides recovery of a surcharge for an electric generation facility shall include a detailed description of the actual costs, as of a date certain, for which the applicant seeks recovery and a detailed description of the impact upon rates of the proposed surcharge.

(v) An application which provides for recovery of a surcharge for an electric generation facility shall include the proposed terms for the capacity, energy, and associated rates for the life of the facility.

(c) Division (B)(2)(d) of section 4928.143 of the Revised Code authorizes an electric utility to include terms, conditions, or charges related to retail shopping by customers. Any application which includes such terms, conditions or charges, shall include, at a minimum, the following information:

(i) A listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or promoting customer shopping for retail electric generation service. Such components would include, but are not limited to, terms and conditions relating to shopping or to returning to the standard service offer and any unavoidable charges. For each such component, an explanation of the component and a descriptive rationale and, to the extent possible, a quantitative justification shall be provided.

(ii) A description and quantification or estimation of any charges, other than those associated with generation expansion or environmental investment under divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, which will be deferred for future recovery, together with the carrying costs, amortization periods, and avoidability of such charges.

(iii) A listing, description, and quantitative justification of any unavoidable charges for standby, back-up, or supplemental power.

(d) Division (B)(2)(e) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for automatic increases or decreases in any component of the standard service offer price. Pursuant to this authority, if the ESP proposes automatic increases or decreases to be implemented during the life of the plan for any component of the standard service offer, other than those covered by division (B)(2)(a) of section 4928.143 of the Revised Code, the electric utility must provide in its application a description of the component, the proposed means for changing the component, and the proposed means for verifying the reasonableness of the change.

(e) Division (B)(2)(f) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the securitization of authorized phase-in recovery of the standard service offer price. If a phase-in deferred asset is proposed to be securitized, the electric utility shall provide, at the time of an application for securitization, a description of the securitization instrument and an accounting of that securitization, including the deferred cash flow due to the phase-in, carrying charges, and the incremental cost of the securitization. The electric utility will also describe any efforts to minimize the incremental cost of the securitization. The electric utility shall provide all documentation associated with securitization, including but not limited to, a summary sheet of terms and conditions. The electric utility shall also provide a comparison of costs associated with securitization with the costs associated with other forms of financing to demonstrate that securitization is the least cost strategy.

(f) Division (B)(2)(g) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions relating to transmission and other specified related services. Moreover, division (A)(2) of section 4928.05 of the Revised Code states that, notwithstanding Chapters 4905. and 4909. of the Revised Code, commission authority under this chapter shall include the authority to provide for the recovery, through a reconcilable rider on an electric distribution utility's distribution rates, of all transmission and transmission-related costs (net of transmission related revenues), including ancillary and net congestion costs, imposed on or charged to the utility by the federal energy regulatory commission or a regional transmission organization, independent transmission operator, or similar organization approved by the federal energy regulatory commission.

Any utility which seeks to create or modify its transmission cost recovery rider in its ESP shall file the rider in accordance with the requirements delineated in Chapter 4901:1-36 of the Administrative Code.

(g) Division (B)(2)(h) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for alternative regulation mechanisms or programs, including infrastructure and modernization incentives, relating to distribution service as part of an ESP. While a number of mechanisms may be combined within a plan, for each specific mechanism or program, the electric utility shall provide a detailed description, with supporting data and information, to allow appropriate evaluation of each proposal, including how the proposal addresses any cost savings to the electric utility, avoids duplicative cost recovery, and aligns electric utility and consumer interests. In general, and to the extent applicable, the electric utility shall also include, for each separate mechanism or program, quantification of the estimated impact on rates over the term of any proposed modernization plan. Any application for an infrastructure modernization plan shall include the following specific requirements:

(i) A description of the infrastructure modernization plan, including but not limited to, the electric utility's existing infrastructure, its existing asset management system and related capabilities, the type of technology and reason chosen, the portion of service territory affected, the percentage of customers directly impacted (non-rate impact), and the implementation schedule by geographic location and/or type of activity. A description of any communication infrastructure included in the infrastructure modernization plan and any metering, distribution automation, or other applications that may be supported by this communication infrastructure also shall be included.

(ii) A description of the benefits of the infrastructure modernization plan (in total and by activity or type), including but not limited to the following as they may apply to the plan: the impacts on current reliability, the number of circuits impacted, the number of customers impacted, the timing of impacts, whether the impact is on the frequency or duration of outages, whether the infrastructure modernization plan addresses primary outage causes, what problems are addressed by the infrastructure modernization plan, the resulting dollar savings and additional costs, the activities affected and related accounts, the timing of savings, other customer benefits, and societal benefits. Through metrics and milestones, the infrastructure modernization plan shall include a description of how the performance and outcomes of the plan will be measured.

(iii) A detailed description of the costs of the infrastructure modernization plan, including a breakdown of capital costs and operating and maintenance expenses net of any related savings, the revenue requirement, including recovery of stranded investment related to replacement of un-depreciated plant with new technology, the impact on customer bills, service disruptions associated with plan implementation, and description of (and dollar value of) equipment being made obsolescent by the plan and reason for early plant retirement. The infrastructure modernization plan shall also include a description of efforts made to mitigate such stranded investment.

(iv) A detailed description of any proposed cost recovery mechanism, including the components of any regulatory asset created by the infrastructure modernization plan, the reporting structure and schedule, and the proposed process for approval of cost recovery and increase in rates.

(v) A detailed explanation of how the infrastructure modernization plan aligns customer and electric utility reliability and power quality expectations by customer class.

(h) Division (B)(2)(i) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for economic development, job retention, and energy efficiency programs. Pursuant to this section, the electric utility shall provide a complete description of the proposal, together with cost-benefit analysis or other quantitative justification, and quantification of the program's projected impact on rates.

(10) Additional required information

Divisions (E) and (F) of section 4928.143 of the Revised Code provide for tests of the ESP with respect to significantly excessive earnings. Division (E) of section 4928.143 of the Revised Code is applicable only if an ESP has a term exceeding three years, and would require an earnings determination to be made in the fourth year. Division (F) of section 4928.143 of the Revised Code applies to any ESP and examines earnings after each year. In each case, the burden of proof for demonstrating that the return on equity is not significantly excessive is borne by the electric utility.

(a) For the annual review pursuant to division (F) of section 4928.143 of the Revised Code, the electric utility shall provide testimony and analysis demonstrating the return on equity that was earned during the year and the returns on equity earned during the same period by publicly traded companies that face comparable business and financial risks as the electric utility. In addition, the electric utility shall provide the following information:

(i) The federal energy regulatory commission form 1 (FERC form 1) in its entirety for the annual period under review. The electric utility may seek protection of any confidential or proprietary data if necessary. If the FERC form 1 is not available, the electric utility shall provide balance sheet and income statement information of at least the level of detail as required by FERC form 1.

(ii) The latest securities and exchange commission form 10-K in its entirety. The electric utility may seek protection of any confidential or proprietary data if necessary.

(iii) Capital budget requirements for future committed investments in Ohio for each annual period remaining in the ESP.

(b) For demonstration under division (E) of section 4928.143 of the Revised Code, the electric utility shall also provide, in addition to the requirements under division (F) of section 4928.143 of the Revised Code, calculations of its projected return on equity for each remaining year of the ESP. The electric utility shall support these calculations by providing projected balance sheet and income statement information for the remainder of the ESP, together with testimony and work papers detailing the methodologies, adjustments, and assumptions used in making these projections.

(D) The first application for an SSO filed after the effective date of section 4928.141 of the Revised Code by each electric utility shall include an ESP and shall be filed at least one hundred fifty days before the electric utility proposes to have such SSO in effect. The first application may also include a proposal for an MRO. First applications that are filed with the commission prior to the initial effective date of this rule and that are determined by the commission to be not in substantive compliance with this rule shall be amended or refiled at the direction of the commission. The commission shall endeavor to make a determination on an amended or refiled ESP application, which substantively conforms to the requirements of this rule, within one hundred fifty days of the filing of the amended or refiled application.

(E) Subsequent applications for an SSO may include an ESP and/or MRO; however, an ESP may not be proposed once the electric utility has implemented an MRO approved by the commission.

(F) The SSO application shall include a section demonstrating that its current corporate separation plan is in compliance with section 4928.17 of the Revised Code, Chapter 4901:1-37 of the Administrative Code, and consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. If any waivers of the corporate separation plan have been granted and are to be continued, the applicant shall justify the continued need for those waivers.

(G) A complete set of work papers must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative or other support of assumptions made in the work papers. Work papers shall be marked, organized, and indexed according to schedules to which they relate. Data contained in the work papers should be footnoted so as to identify the source document used.

(H) All schedules, tariff sheets, and work papers prepared by, or at the direction of, the electric utility for the application and included in the application must be available in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers. The electronic form does not have to be filed with the application but must be made available within two business days to staff and any intervening party that requests it.

Replaces: 4901:1-35-03
Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.14, 4928.141, 4928.142, 4928.143
Prior effective date: 5/27/04

4901:1-35-04 <u>Service of application</u>.

(A) Concurrent with the filing of a standard service offer (SSO) application and the filing of any waiver requests, the electric utility shall provide notice of filings to each party in its most recent SSO proceeding or, if this is its first SSO filing after the effective date of section 4928.141 of the Revised Code, then its last rate plan proceeding. At a minimum, that notice shall state that a copy of the application and all waiver requests are available through the electric utility's and commission's web sites, available at the electric utility's main office, available at the commission's offices, and any other sites at which the electric utility will maintain a copy of the application and all waiver requests.

(B) The electric utility shall also submit with its SSO application a proposed notice for newspaper publication that fully discloses the substance of the application, including projected rate impacts, and that prominently states that any person may request to become a party to the proceeding.

(C) The electric utility shall provide electronic copies of the application upon request, without cost, and transmit the application within five business days, or make a hard copy available for review at the electric utility's business office. Upon request, electronic copies shall be provided in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers.

Replaces: 4901:1-35-04
Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
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Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.14, 4928.141, 4928.142, 4928.143
Prior effective date: 5/27/04

4901:1-35-05 Technical conference.

Upon filing of a standard service offer application, the commission, legal director, deputy legal director, or attorney examiner shall schedule a technical conference. The purpose of the technical conference is to allow interested persons an opportunity to better understand the electric utility's application. The electric utility will have the necessary personnel in attendance at this conference so as to explain, among other things, the structure of the filing, the work papers, the data sources, and the manner in which methodologies were devised. The conference will be held at the commission offices, unless the commission, legal director, deputy legal director, or attorney examiner determines otherwise.

Replaces: 4901:1-35-05
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Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.14, 4928.141, 4928.142, 4928.143
Prior effective date: 5/27/04

4901:1-35-06 Hearings.

(A) After the filing of a standard service offer application that conforms to the commission's rules, the commission shall set the matter for hearing and shall cause notice of the hearing to be published one time in a newspaper of general circulation in each county in the electric utility's certified territory. At such hearing, the burden of proof to show that the proposals in the application are just and reasonable and are consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code shall be upon the electric utility.

(B) Interested persons wishing to participate in the hearing shall file a motion to intervene no later than forty-five days after the issuance of the entry scheduling the hearing, unless ordered otherwise by the commission, legal director, deputy legal director, or attorney examiner. This rule does not prohibit the filing of a motion to intervene and conducting discovery prior to the issuance of an entry scheduling a hearing.

Replaces: 4901:1-35-06
Effective: 5/7/09
R.C. 119.032 review date: 9/30/13

Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.14, 4928.141, 4928.142, 4928.143
Prior effective date: 5/27/04

4901:1-35-07 Discoverable agreements.

Upon submission of an appropriate discovery request during a proceeding establishing a standard service offer, an electric utility shall make available to the requesting party every contract or agreement that is between the electric utility or any of its affiliates and a party to the proceeding, consumer, electric service company, or political subdivision and that is relevant to the proceeding, subject to such protection for proprietary or confidential information as is determined appropriate by the commission.

Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.145

4901:1-35-08 Competitive bidding process requirements and use of independent third party.

(A) An electric utility proposing a market-rate offer in its standard service offer application, pursuant to section 4928.142 of the Revised Code, shall propose a plan for a competitive bidding process (CBP). The CBP plan shall comply with the requirements set forth in paragraph (B) of rule 4901:1-35-03 of the Administrative Code. The electric utility shall use an independent third party to design an open, fair, and transparent competitive solicitation; to administer the bidding process; and to oversee the entire procedure to assure that the CBP complies with the CBP plan. The independent third party shall be accountable to the commission for all design, process, and oversight decisions. The independent third party shall incorporate into the solicitation such measures as the commission may prescribe, and shall incorporate into the bidding process any direction the commission may provide. Any modifications or additions to the approved CBP plan requested by the independent third party shall be submitted to the commission for review prior to implementation.

(B) Within twenty-four hours after the completion of the bidding process, the independent third party shall submit a report to the commission summarizing the results of the CBP. The report shall include, but not be limited to, the following items:

(1) A description of the conduct of the bidding process, including a discussion of any aspects of the process that the independent third party believes may have adversely affected the outcome.

(2) The level(s) of oversubscription for each product.

(3) The number of bidders for each product.

(4) The percentage of each product that was bid upon by persons other than the electric utility.

(5) The independent third party's evaluation of the submitted bids, including the bidders' generation source and financial capabilities to perform.

(6) The independent third party's final recommendation of the least cost winning bidder(s).

(7) A listing of the retail rates that would result from the least cost winning bids, along with any descriptions, formulas, and/or tables necessary to demonstrate how the conversion from winning

bid(s) to retail rates was accomplished under the conversion process approved by the commission in the electric utility's CBP plan.

(C) The electric utility shall provide access to staff and any consultant hired by the commission to assist in review of the CBP of any and all data, information, and communications pertaining to the bidding process, on a real time basis, regardless of the confidential nature of such data and information.

(D) The commission shall make the final selection of the least-cost winning bidder(s) of the CBP. The commission may rely upon the information provided in the independent third party's report in making its selection of the least-cost winning bidder(s) of the CBP.

Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.142

4901:1-35-09 Electric security plan fuel and purchased power adjustments.

(A) Each electric utility for which the commission has approved an electric security plan (ESP) which includes automatic adjustments under division (B)(2)(a) of section 4928.143 of the Revised Code shall file for such adjustments in accordance with the provisions of this rule.

(B) The electric utility shall calculate a proposed quarterly adjustment based on projected costs and reconciliation requirements by filing an application four times per year. The staff shall review the quarterly filing for completeness and computational accuracy. If staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date. Although rates are to be adjusted and provided on a quarterly basis, the cost information shall be summarized monthly.

(C) On an annual basis, the prudence of the costs incurred and recovered through quarterly adjustments shall be reviewed in a separate proceeding outside of the automatic recovery provision of the electric utility's ESP. The electric utility shall demonstrate that the costs were prudently incurred as required under division (B)(2)(a) of section 4928.143 of the Revised Code and, if a significant change in costs has incurred, include an analysis comparing the electric utility's resource and/or environmental compliance strategy with supply and demand-side alternatives. The process and timeframes for that separate proceeding shall be set by order of the commission, the legal director, deputy legal director, or attorney examiner.

(D) The commission may order that consultants be hired, with the costs billed to the electric utility, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments.

Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.143

4901:1-35-10 Annual review of electric security plan.

By May fifteenth of each year, the electric utility shall make a separate filing with the commission demonstrating whether or not any rate adjustments authorized by the commission as part of the electric utility's electric security plan resulted in significantly excessive earnings during the review period as measured by division (F) of section 4928.143 of the Revised Code. The process and timeframes for that proceeding shall be set by order of the commission, the legal director, or attorney examiner. The electric utility's filing shall include the information set forth in paragraph (C) of rule 4901:1-35-03 of the Administrative Code as it relates to excessive earnings.

Effective: 5/7/09
R.C. 119.032 review date: 9/30/13
Promulgated under: R.C. 111.15
Statutory authority: R.C. 4928.06, 4928.141
Rule amplifies: RC 4928.143

4901:1-35-11 Competitive bidding process ongoing review and reporting requirements.

(A) The initial market rate offer (MRO), and subsequent offers, implemented by each electric utility that, as of July 31, 2008, directly owned, in whole or in part, operating electric generation facilities that had been used and useful in this state, shall include a blended price for electric generation services for the first five years of the MRO, or some other period determined by the commission under section 4928.142 of the Revised Code.

(B) Once a competitive bidding process (CBP) plan subject to a price blending period is approved by the commission pursuant to section 4928.142 of the Revised Code, the electric utility shall file its proposed adjustments to the standard service offer (SSO) portion of the blended rates of its CBP in a filing to the commission on a quarterly basis (quarterly filing) for the duration of the price blending period of the CBP plan, on specific dates to be determined by the commission.

(1) The quarterly filing shall include a separate listing of each cost or cost component including costs for fuel, purchased power, alternative portfolio requirements, and environmental compliance, in comparison with the costs or cost components included in the most recent SSO and the previously existing level of each cost. Any offsetting benefits, as defined in division (D) of section 4928.142 of the Revised Code, obtained directly or as a result of expenditures in the specified cost areas shall be listed separately and be used to reduce the cost levels requested for recovery. Rates are to be adjusted on a quarterly basis. Such adjustments may include, or be made pursuant to, the application of incentive factors or formulas that the commission determined to be reasonable in its approval of the CBP plan. The cost information shall consist of monthly data submitted on a quarterly basis.

(2) The quarterly filing shall include any descriptions, formulas, and/or tables necessary to show how the adjusted cost levels are translated into blended CBP rates.

(3) The electric utility shall provide projections, in its quarterly filing, of any impacts that the proposed adjustments will have on its return on common equity.

(4) The staff shall review the quarterly filing for completeness, computational accuracy, and consistency with prior commission determinations regarding the adjustments. If the staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date.

(5) On an annual basis, or other basis as determined by the commission, the prudence of the costs incurred and recovered through quarterly adjustments to the electric utility's SSO portion of the blended rates shall be reviewed. The commission shall determine the frequency of the review and shall establish a schedule for the review process. The commission may order that consultants be

hired, with the cost to be billed to the company, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments. The cost to the electric utility of the commission's use of such consultants may be included by the electric utility in its quarterly rate adjustment filing.

(C) If the CBP plan is approved by the commission subject to a price blending period, approximately one year after filing the CBP plan, and annually thereafter for the duration of the price blending period of the CBP plan, on dates to be determined by the commission, the electric utility shall file an annual report on its CBP.

(1) The annual report shall provide a general statement about the operation of the CBP to date. The annual status report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP service and the resulting blended rates on the electric utility's customers.

(2) The annual report shall describe any defaults and/or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated and/or known for the following year.

(4) The annual report shall describe the financial condition of the electric utility, its current and projected return on common equity, and the return on common equity of publicly traded companies that face comparable business and financial risk. The electric utility shall show that its earnings under the price blending period will not be significantly excessive as compared with similarly situated companies. Information submitted by the electric utility to demonstrate its projected earnings shall include, but not be limited to, balance sheet information, income statement information, and capital budget requirements for future investments in Ohio. This information should be provided separately for generation, transmission, and distribution for the electric utility and its affiliates. Additionally, the electric utility shall provide testimony and analysis demonstrating the return on equity earned by publicly traded companies that face comparable business and financial risks as the electric utility.

(5) If in an emergency situation the electric utility claims that its financial integrity is threatened by the operation of the CBP price blending period, it shall demonstrate its claim through information and data filed in its annual report. The electric utility has the burden of proof in any such claim of threatened financial integrity.

(6) The electric utility shall discuss, in its annual report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(7) The annual report shall describe the blended phase-in rates projected to be charged to its customers under the continuation of the CBP plan, as modified pursuant to paragraph (C)(6) of this rule. The rate projections shall show the existing and projected generation service price(s) blended with the CBP determined rates and projected CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending is accomplished. The projected blended phase-in rates shall be compared in the annual report to the existing blended phase-in rates.

(8) The annual report shall describe the operation to date of any time-differentiated and dynamic rate designs implemented under the CBP, the approaches used to communicate price and usage information to consumers, and observed price elasticity.

(9) The annual report shall include a status report of the market conditions relevant to the continued operation of the electric utility's MRO, including but not limited to information about the existence of published source(s) of electric market pricing information, whether the electric utility or its affiliate still belongs to an regional transmission organization (RTO), and whether the RTO's market monitoring function has mitigation authority over the transactions resulting from the CBP.

(10) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or requests set forth in the annual report, and set any necessary schedules through an entry.

(D) If the CBP plan is approved by the commission without the requirement of a price blending period, or after the expiration of any such required price blending period, on an annual basis, on dates to be determined by the commission, the electric utility shall file an annual report with the commission.

(1) The annual report shall provide a general statement about the operation of the CBP to date. The annual report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP on the electric utility's customers' rates.

(2) The annual report shall describe any defaults or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated or known for the following year.

(4) The electric utility shall discuss, in its annual report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(5) The annual report shall describe the operation to date of any time-differentiated and dynamic rate designs implemented under the CBP, the approaches used to communicate price and usage information to consumers, and observed price elasticity.

(6) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or requests set forth in the annual report, and set any necessary schedules through an entry.

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PUCO CHAPER 4901:1-39

ENERGY EFFICIENCY AND DEMAND REDUCTION BENCHMARKS

4901:1-39-01 Definitions Effective: 12/10/2009

(A) "Achievable potential" means the reduction in energy usage or peak demand that would likely result from the expected adoption by homes and businesses of the most efficient, cost-effective measures, given effective program design, taking into account remaining barriers to customer adoption of those measures. Barriers may include market, financial, political, regulatory, or attitudinal barriers, or the lack of commercially available product. "Achievable potential" is a subset of "economic potential."

(B) "Anticipated savings" means the reduction in energy usage or peak demand that will accrue from contractual commitments for program participation made in the reporting period, which measures in such programs are scheduled for installation in the subsequent reporting periods.

(C) "Capital stock" means all devices, equipment, and processes that use or convert energy.

(D) "Coincident peak-demand savings" means the demand savings for energy efficiency measures that are expected to occur during the summer on-peak period which is defined as June through August on weekdays between 3:00 p.m. and 6:00 p.m.

(E) "Commission" means the public utilities commission of Ohio.

(F) "Cost effective" means the measure, program, or portfolio being evaluated that satisfies the total resource cost test.

(G) "Demand response" means a change in customer behavior or a change in customer-owned or operated assets that affects the demand for electricity as a result of price signals or other incentives.

(H) "Economic potential" means the reduction in energy usage or peak demand that would result if all homes and businesses adopted the most efficient and cost-effective measures. Economic potential is a subset of the "technical potential."

(I) "Electric utility" has the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(J) "Energy baseline" means the average total kilowatt-hours of distribution service sold to retail customers of the electric utility in the preceding three calendar years as reported in the electric utility's most recent long-term forecast report, pursuant to division (A)(2)(a) of section 4928.66 of the Revised Code. The total kilowatt-hours sold shall equal the total kilowatt-hours delivered by the electric utility.

(K) "Energy benchmark" means the annual level of energy savings that an electric utility must achieve as provided in division (A)(1)(a) of section 4928.66 of the Revised Code.

(L) "Energy efficiency" means reducing the consumption of energy while maintaining or improving the end-use customer's existing level of functionality, or while maintaining or improving the utility system functionality.

(M) "Independent program evaluator" means the person(s) hired by one or more of the electric utilities, at the direction of the commission, to complete the following activities:

(1) Monitor, verify, evaluate, and report on the electric energy savings and peak-demand reductions resulting from utility program and mercantile customer activities.

(2) Determine program and portfolio cost-effectiveness.

(3) Conduct program process evaluations.

(4) Perform due-diligence reviews of evaluations or documentation provided by an electric utility or mercantile customer, as directed by the commission. Such person shall work at the sole direction of the commission.

(N) "Market transformation" means a lasting structural or behavioral change in the marketplace that increases customer adoption of energy efficiency or peak reduction measures that will be sustained after any program promoting such behavior ceases.

(O) "Measure" means any material, device, technology, operational practice, or educational program that makes it possible to deliver a comparable level and quality of end-use energy service while using less energy or less capacity than would otherwise be required.

(P) "Mercantile customer" has the meaning set forth in division (A)(19) of section 4928.01 of the Revised Code.

(Q) "Nonenergy benefits" mean societal benefits that do not affect the calculation of program cost-effectiveness pursuant to the total resource cost test including but not limited to benefits of low-income customer participation in utility programs; reductions in greenhouse gas emissions, regulated air emissions, water consumption, natural resource depletion to the extent the benefit of such reductions are not fully reflected in cost savings; enhanced system reliability; or advancement of any other state policy enumerated in section 4928.02 of the Revised Code.

(R) "Peak demand," when measuring reduction programs, means the average maximum hourly electricity usage during the highest 100 hours on the electric utility's system in a calendar year.

(S) "Peak-demand baseline" means the average peak demand on the electric utility's system in the preceding three calendar years as reported in the electric utility's most recent long-term forecast report, pursuant to division (A)(2)(a) of section 4928.66 of the Revised Code.

(T) "Peak-demand benchmark" means the reduction in peak demand an electric utility's system must achieve as provided in division (A)(1)(b) of section 4928.66 of the Revised Code.

(U) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(V) "Program" means a single offering of one or more measures provided to consumers. For example, a weatherization program may include insulation replacement, weather stripping, and window replacement measures.

(W) "Staff" means the staff or authorized representative of the public utilities commission.

(X) "Technical potential" means the reduction in energy usage or peak demand that would result if all homes and businesses adopted the most efficient measures, regardless of cost.

(Y) "Total resource cost test" means an analysis to determine if, for an investment in energy efficiency or peak-demand reduction measure or program, on a life-cycle basis, the present value of the avoided supply costs for the periods of load reduction, valued at marginal cost, are greater than the present value of the monetary costs of the demand-side measure or program borne by both the electric utility and the participants, plus the increase in supply costs for any periods of increased load resulting directly from the measure or program adoption. Supply costs are those costs of supplying energy and/or capacity that are avoided by the investment, including generation, transmission, and distribution to customers. Demand-side measure or program costs include, but are not limited to, the costs for equipment, installation, operation and maintenance, removal of replaced equipment, and program administration, net of any residual benefits and avoided expenses such as the comparable costs for devices that would otherwise have been installed, the salvage value of removed equipment, and any tax credits.

(Z) "Verified savings" means an annual reduction of energy usage or peak demand from an energy efficiency or peak-demand reduction program directly measured or calculated using reasonable statistical and/or engineering methods consistent with approved measurement and verification guidelines.

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4901:1-39-02 Purpose and Scope Effective: 12/10/2009

(A) Pursuant to division (A)(1)(a) of section 4928.66 of the Revised Code, beginning in 2009, each electric utility is required to implement energy efficiency programs. Such programs, at a minimum, shall achieve established statutory benchmarks for energy efficiency. Additionally, pursuant to division (A)(1)(b) of section 4928.66 of the Revised Code, beginning in 2009, each electric utility is required to implement peak-demand reduction programs designed to achieve established statutory benchmarks for peak-demand reduction. The purpose of this chapter is to establish rules for the implementation of electric utility programs that will encourage innovation and market access for cost-effective energy efficiency and peak-demand reduction, achieve the statutory benchmark for peak-demand reduction, meet or exceed the statutory benchmark for energy efficiency, and provide for the participation of stakeholders in developing energy efficiency and peak-demand reduction programs for the benefit of the state of Ohio.

(B) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

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4901:1-39-03 Program Planning Requirements Effective: 12/10/209

(A) Assessment of potential. Prior to proposing its comprehensive energy efficiency and peak-demand reduction program portfolio plan, an electric utility shall conduct an assessment of potential energy savings and peak-demand reduction from adoption of energy efficiency and demand-response measures within its certified territory, which will be included in the electric utility's program portfolio filing pursuant to rule 4901:1-39-04 of the Administrative Code. An electric utility may collaborate with other electric utilities to co-fund or conduct such an assessment on a broader geographic basis than its certified territory. However, such an assessment must also disaggregate results on the basis of each electric utility's certified territory. Such assessment shall include, but not be limited to, the following:

1) Analysis of technical potential. Each electric utility shall survey and characterize the energy-using capital stock located within its certified territory and quantify its actual and projected energy use and peak demand. Based upon the survey and characterization, the electric utility shall conduct an analysis of the technical potential for energy efficiency and peak-demand reduction obtainable from applying alternate measures.

(2) Analysis of economic potential. For each alternate measure identified in its assessment of technical potential, the electric utility shall conduct an assessment of cost-effectiveness using the total resource cost test.

(3) Analysis of achievable potential. For each alternate measure identified in its analysis of economic potential as cost-effective, the electric utility shall conduct an analysis of achievable potential. Such analysis shall consider the ability of the program design to overcome barriers to customer adoption, including, but not limited to, appropriate bundling of measures.

(4) For each measure considered, the electric utility shall describe all attributes relevant to assessing its value, including, but not limited to potential energy savings or peak-demand reduction, cost, and nonenergy benefits.

(B) Program design criteria. When developing programs for inclusion in its program portfolio plan, an electric utility shall consider the following criteria:

(1) Relative cost-effectiveness.

2) Benefit to all members of a customer class, including nonparticipants.

(3) Potential for broad participation within the targeted customer class.

(4) Likely magnitude of aggregate energy savings or peak-demand reduction.

(5) Nonenergy benefits.

(6) Equity among customer classes.

(7) Relative advantages or disadvantages of energy efficiency and peak-demand reduction programs for the construction of new facilities, replacement of retiring capital stock, or retrofitting existing capital stock.

(8) Potential to integrate the proposed program with similar programs offered by other utilities, if such integration produces the most cost-effective result and is in the public interest.

(9) The degree to which a program bundles measures so as to avoid lost opportunities to attain energy savings or peak reductions that would not be cost-effective or would be less cost-effective if installed individually.

(10) The degree to which the program design engages the energy efficiency supply chain and leverages partners in program delivery.

(11) The degree to which the program successfully addresses market barriers or market failures.

(12) The degree to which the program leverages knowledge gained from existing program successes and failures.

(13) The degree to which the program promotes market transformation.

(C) Promising measures not selected. Each electric utility shall identify measures considered but not found to be cost-effective or achievable but show promise for future deployment. The electric utility shall identify potential actions that it could undertake to improve the measure's technical potential, economic potential, and achievable potential to enhance the likelihood that the measure would become cost-effective and reasonably achievable.

(D) The electric utility may seek to collaborate or consult with other utilities, regional and municipal governmental organizations, nonprofit organizations, businesses, and other stakeholders to develop programs meeting the requirements of this chapter.

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4901:1-39-04 Program Portfolio Plan and Filing Requirements Effective: 12/10/2009

(A) Each electric utility shall design and propose a comprehensive energy efficiency and peak-demand reduction program portfolio, including a range of programs that encourage innovation and market access for cost-effective energy efficiency and peak-demand reduction for all customer classes, which will achieve the statutory benchmarks for peak-demand reduction, and meet or exceed the statutory benchmarks for energy efficiency. An electric utility's first program portfolio plan filed pursuant to this rule shall be filed with supporting testimony prior to January 1, 2010. Each electric utility shall file an updated program portfolio plan by April 15, 2013, and by the fifteenth of April every third year thereafter, unless otherwise directed by the commission.

(B) Each electric utility shall demonstrate that its program portfolio plan is cost-effective on a portfolio basis. In general, each program proposed within a program portfolio plan must also be cost-effective, although each measure within a program need not be cost-effective. However, an electric utility may include a program within its program portfolio plan that is not cost-effective when that program provides substantial nonenergy benefits.

(C) Content of filing. An electric utility's program portfolio plan shall include, but not be limited to, the following:

(1) An executive summary and its assessment of potential pursuant to paragraph (A) of rule 4901:1-39-03 of the Administrative Code.

(2) A description of stakeholder participation in program planning efforts and program portfolio development.

(3) A description of attempts to align and coordinate programs with other public utilities' programs.

(4) A description of existing programs. The electric utility shall provide a summary of existing programs with a recommendation for whether the program should continue and, if so, a description of its relationship to any proposed programs. If a program has previously been approved and is unchanged, the electric utility may reference the program description currently in effect. If the electric utility is proposing to modify an existing program, the electric utility shall provide a description of the proposed modification and the basis for proposed changes.

(5) A description of proposed programs. An electric utility shall describe each program proposed to be included within its program portfolio plan with at least the following information:

(a) A narrative describing why the program is recommended pursuant to the program design criteria in this chapter.

(b) Program objectives, including projections and basis for calculating energy savings and/or peak-demand reduction resulting from the program.

(c) The targeted customer sector.

(d) The proposed duration of the program.

(e) An estimate of the level of program participation.

(f) Program participation requirements, if any.

(g) A description of the marketing approach to be employed, including rebates or incentives offered through each program, and how it is expected to influence consumer choice or behavior.

(h) A description of the program implementation approach to be employed.

(i) A program budget with projected expenditures, identifying program costs to be borne by the electric utility and collected from its customers, with customer class allocation, if appropriate.

(j) Participant costs, if any.

(k) Proposed market transformation activities, if any, which have been identified and proposed to be included in the program portfolio plan.

(l) A description of the plan for preparing reports that document the electric utility's evaluation, measurement, and verification of the energy savings and/or peak-demand reduction resulting from each program and the process evaluations conducted by the electric utility. The independent program evaluator will prepare an independent evaluation, measurement, and verification plan at the direction of the commission staff to monitor, verify, evaluate and report on the energy savings and peak-demand reductions resulting from utility programs and mercantile customer activities. The independent program evaluator's plan may rely on data collected and reported by the electric utility.

(D) Unless otherwise ordered by the commission, any person may file objections within sixty days after the filing of an electric utility's program portfolio plan. Any person filing objections shall specify the basis for all objections, including any proposed additional or alternative programs, or modifications to the electric utility's proposed program portfolio plan.

(E) The commission shall set the matter for hearing and shall cause notice of the hearing to be published one time in a newspaper of general circulation in each county in the electric utility's certified territory. At such hearing, the electric utility shall have the burden to prove that the proposed program portfolio plan is consistent with the policy of the state of Ohio as set forth in section 4928.02 of the Revised Code, and meets the requirements of section 4928.66 of the Revised Code.

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4901:1-39-05 Benchmark and Annual Status Reports Effective: 12/10/2009

(A) Initial benchmark report. Within sixty days of the effective date of this rule, each electric utility shall file an initial benchmark report with the commission that identifies the following information:

(1) The energy and demand baselines for kilowatt-hour sales and kilowatt demand for the reporting year; including a description of the method of calculating the baseline, with supporting data.

(2) The applicable statutory benchmarks for energy savings and electric utility peak-demand reduction.

(B) An electric utility may file an application to adjust its sales and/or demand baseline. The baseline shall be normalized for weather and for changes in numbers of customers, sales, and peak demand to the extent such changes are outside the control of the electric utility. The electric utility shall include in its application all assumptions, rationales, and calculations, and shall propose methodologies and practices to be used in any proposed adjustments or normalizations. To the extent approved by the commission, normalizations for weather, changes in numbers of customers, sales, and peak demand shall be consistently applied from year to year.

(C) Portfolio status report. By March fifteenth of each year, each electric utility shall file a portfolio status report addressing the performance of all approved energy efficiency and peak-demand reduction programs in its program portfolio plan over the previous calendar year which includes, at a minimum, the following information:

(1) Compliance demonstration. Each electric utility shall include a section in its portfolio status report detailing its achieved energy savings, achieved demand reductions, and the expected demand reductions that its programs were reasonably designed to achieve, relative to its corresponding baselines. At a minimum, this section of the portfolio status report shall include each of the following:

(a) An update to its benchmark report.

(b) A comparison with the applicable benchmark of actual energy savings and peak-demand reductions achieved by electric utility programs.

(c) An affidavit as to whether the reported performance complies with the statutory benchmarks.

(2) Program performance assessment. Each electric utility shall include a section in its portfolio status report demonstrating whether it has successfully implemented the energy efficiency and demand-reduction programs approved in its program portfolio plan. At a minimum, this section of the annual portfolio status report shall include each of the following:

(a) A description of each approved energy efficiency or peak-demand reduction program implemented in the previous calendar year including:

(i) The key activities undertaken in each program, the number and type of participants, a comparison of the forecasted savings to the verified savings achieved by such program, the magnitude of anticipated savings, and a trend analysis of how anticipated savings will be realized over the life of the program.

(ii) All energy savings counted toward the applicable benchmark as a result of energy efficiency improvements implemented by mercantile customers and committed to the electric utility.

(iii) All peak-demand reductions counted toward the applicable benchmark as a result of energy efficiency improvements, demand response, or demand reduction improvements implemented by mercantile customers and committed to the electric utility.

(iv) A description of all transmission and distribution infrastructure improvements made by the electric utility that reduce line losses to the extent the reduction in line losses has been applied to meet the applicable benchmarks with a calculation and description of the net impact of such improvements on losses.

(b) An evaluation, measurement, and verification report that documents the energy savings and peak-demand reduction values and the cost-effectiveness of each energy efficiency and demand-side management program reported in the electric utility's portfolio status report. Such report shall include documentation of any process evaluations and expenditures, measured and verified savings, and cost-effectiveness of each program. Measurement and verification processes shall confirm that the measures were actually installed, the installation meets reasonable quality standards, and the measures are operating correctly and are expected to generate the predicted savings. Upon commission order, the staff may publish guidelines for program measurement and verification.

(c) A recommendation for whether each program should be continued, modified, or eliminated. The electric utility may propose alternative programs to replace eliminated programs, taking into account the overall balance of programming in its program portfolio plan. The electric utility shall describe any alternate program or program modification by providing at least the information required for proposed programs in its program portfolio plan pursuant to this chapter. An electric utility may seek written staff approval to reallocate funds between programs serving the same customer class at any time, provided that the reallocation supports the goals of its approved program portfolio plan and is limited to no more than twenty-five per cent of the funds available for programs serving that customer class. In addition, an electric utility may change its program mix or budget allocations at any time, as long as it provides notice to all parties in the proceeding in which the program portfolio plan was approved.

(D) Independent program evaluator report. Subsequent to the filing of the electric utility's portfolio status report, the independent program evaluator will prepare and file a report of the independent program evaluator's activities and conclusions in monitoring, verifying, and evaluating the energy savings and peak-demand reductions resulting from the electric utility programs and mercantile customer activities. The report shall also include the verification and evaluation, through the use of due-diligence techniques including project inspections, of the electric utility's evaluation, measurement, and verification report.

(E) An electric utility may satisfy its peak-demand reduction benchmarks through a combination of energy efficiency and peak-demand response programs implemented by electric utilities and/or programs implemented on mercantile customer sites where the mercantile program is committed to the electric utility.

(1) For energy efficiency programs, an electric utility may count the programs' effects resulting in coincident peak-demand savings.

(2) For demand response programs, an electric utility may count demand reductions towards satisfying some or all of the peak-demand reduction benchmarks by demonstrating that either the electric utility has reduced its actual peak demand, or has the capability to reduce its peak demand and such capability is created under either of the following circumstances:

(a) A peak-demand reduction program meets the requirements to be counted as a capacity resource under the tariff of a regional transmission organization approved by the Federal Energy Regulatory Commission.

(b) A peak-demand reduction program equivalent to a regional transmission organization program, which has been approved by this commission.

(F) A mercantile customer's energy savings and peak-demand reductions shall be measured by including the effects of all demand-response programs of the mercantile customer and all mercantile customer-sited energy efficiency and peak-demand reduction programs. A mercantile customer's energy savings and peak-demand reductions shall be presumed to be the effect of a demand response, energy efficiency, or peak-demand reduction program to the extent they involve the early retirement of fully functioning equipment, or the installation of new equipment that achieves reductions in energy use and peak demand that exceed the reductions that would have occurred had the customer used standard new equipment or practices where practicable. Electric utilities may make an alternative demonstration that mercantile customer energy savings or peak demand reductions are effects of such a program.

(G) A mercantile customer may file, either individually or jointly with an electric utility, an application to commit the customer's demand reduction, demand response, or energy efficiency programs for integration with the electric utility's demand reduction, demand response, and energy efficiency programs, pursuant to division (A)(2)(d) of section 4928.66 of the Revised Code. Such application shall:

(1) Address coordination requirements between the electric utility and the mercantile customer with regard to voluntary reductions in load by the mercantile customer, which are not part of an electric utility program, including specific communication procedures.

(2) Grant permission to the electric utility and staff to measure and verify energy savings and/or peak-demand reductions resulting from customer-sited projects and resources.

(3) Identify all consequences of noncompliance by the customer with the terms of the commitment.

(4) Include a copy of the formal declaration or agreement that commits the mercantile customer's programs for integration, including any requirement that the electric utility will treat the customer's information as confidential and will not disclose such information except under an appropriate protective agreement or a protective order issued by the commission pursuant to rule 4901-1-24 of the Administrative Code.

(5) Include a description of all methodologies, protocols, and practices used or proposed to be used in measuring and verifying program results, and identify and explain all deviations from any program measurement and verification guidelines that may be published by the commission.

(H) An electric utility shall not count in meeting any statutory benchmark the adoption of measures that are required to comply with energy performance standards set by law or regulation, including but not limited to, those embodied in the Energy Independence and Security Act of 2007, or an applicable building code.

(I) Benchmarks not reasonably achievable. If an electric utility determines that it is unable to meet a benchmark due to regulatory, economic, or technological reasons beyond its reasonable control, the electric utility may file an application to amend its benchmarks. To the extent that forecasted peak demand and peak prices do not materialize for economic reasons, the electric utility may be granted a waiver of its benchmark for the difference between actual performance and expected performance of demand response programs.

(J) Benchmarks not reasonably achievable. If an electric utility determines that it is unable to meet a benchmark due to regulatory, economic, or technological reasons beyond its reasonable control, the electric utility may file an application to amend its benchmarks. To the extent that forecasted peak demand and peak prices do not materialize for economic reasons, the electric utility may be granted a waiver of its benchmark for the difference between the actual and expected performance of demand response programs. In any such application, the electric utility shall demonstrate that it has exhausted all reasonable compliance options.

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4901:1-39-06 Review of Annual Reports and Issuance of the Commission Verification Report — Effective: 12/10/2009

(A) Any person may file comments regarding an electric utility's initial benchmark report or annual portfolio status report filed pursuant to this chapter within thirty days of the filing of such report.

(B) Upon receipt of such report, the staff shall review the report and any timely filed comments, and file its findings and recommendations regarding program implementation and compliance with the applicable benchmarks, and any proposed modifications thereto, verifying the electric utility's compliance or noncompliance with its approved program portfolio plan and the mandated energy efficiency improvements and peak-demand reductions. If staff finds that an electric utility has not demonstrated compliance with the approved program portfolio plan or annual sales or peak-demand reductions required by division (A) of section 4928.66 of the Revised Code, staff may recommend remedial action and/or the assessment of a forfeiture. Additionally, the staff may recommend modifications to a program within the electric utility's program portfolio plan.

(C) The commission may schedule a hearing on the electric utility's portfolio benchmark report or status report. If staff recommends a forfeiture, the commission shall schedule a hearing on the staff's recommendations.

(D) The commission shall adopt, or modify and adopt, the staff's recommendations and findings as its annual verification report of the electric utility's achieved energy efficiency and peak-demand reductions pursuant to division (B) of section 4928.66 of the Revised Code. Such verification report shall be provided to the consumers' counsel of Ohio.

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4901:1-39-07 Recovery Mechanism Effective: 12/10/2009

(A) With the filing of its proposed program portfolio plan, the electric utility may submit a request for recovery of an approved rate adjustment mechanism, commencing after approval of the electric utility's program portfolio plan, of costs due to electric utility peak-demand reduction, demand response, energy efficiency program costs, appropriate lost distribution revenues, and shared savings. Any such recovery shall be subject to annual reconciliation after issuance of the commission verification report issued pursuant to this chapter.

(1) The extent to which the cost of transmission and distribution infrastructure investments that are found to reduce line losses may be classified as or allocated to energy efficiency or peak-demand reduction programs, pursuant to division (A)(2)(d) of section 4928.66 of the Revised Code, shall be limited to the portion of those investments that are attributable to and undertaken primarily for energy efficiency or demand reduction purposes.

(2) Mercantile customers, who commit their peak-demand reduction, demand response, or energy efficiency projects for integration with the electric utility's programs as set forth in rule 4901:1-39-08 of the Administrative Code, may individually or jointly with the electric utility, apply for exemption from such recovery.

(B) Any person may file objections within thirty days of the filing of an electric utility's application for recovery. If the application appears unjust or unreasonable, the commission may set the matter for hearing.

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4901:1-39-08 Mercantile Customer Exemptions Effective: 12/10/2009

An application to commit a mercantile customer program for integration filed pursuant to paragraph G of rule 4901:1-39-05 of the Administrative Code, may include a request for an exemption from the cost recovery mechanism set forth in rule 4901:1-39-07 of the Administrative Code. To be eligible for such exemption, the mercantile customer must consent to providing an annual report on the energy savings and electric utility peak-demand reductions achieved in the customer's facilities in the most recent year. The report shall include the following:

(A) A demonstration that energy savings and peak-demand reductions associated with the mercantile customer's program are the result of investments that meet the total resource cost test, or that the electric utility's avoided cost exceeds the cost to the electric utility for the mercantile customer's program.

(B) A statement distinguishing programs implemented before and after January 1, 2009, or in future reports filed for years subsequent to 2009, before and after the most recent year.

(C) A quantification of the energy savings or peak-demand reductions for programs initiated prior to 2009 in the baseline period, recognizing that programs may have diminishing effects over time as technology evolves or equipment degrades.

(D) A recognition that the energy saving and demand reduction effects during the electric utility's baseline period of any mercantile customer-sited energy efficiency or peak-demand reduction programs that are integrated into an electric utility's programs are excluded from the electric utility's baselines by increasing its baseline for energy savings and baseline for peak-demand reductions by the amount of mercantile customer energy savings and demand reductions.

(E) A listing and description of the customer programs implemented, including measures taken, devices or equipment installed, processes modified, or other actions taken to increase energy efficiency and reduce peak demand, including specific details such as the number, type, and efficiency levels both of the installed equipment and the old equipment that is being replaced, if applicable.

(F) An accounting of expenditures made by the mercantile customer for each program and its component energy savings and electric utility peak-demand reduction attributes.

(G) The timeline showing when each program went into effect, and when the energy savings and peak-demand reductions occurred.

(H) Any request for an exemption may be combined with any other reasonable arrangement, approved pursuant to Chapter 4901:1-38 of the Administrative Code, if such reasonable arrangement contains appropriate measurements and verification of program results.

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PUCO CHAPTER 4901:1-40

ALTERNATIVE ENERGY PORTFOLIO STANDARD

Ohio Public Utilities Commission	Chapter 4901:1-40 Alternative Energy Portfolio Standard.

4901:1-40-01 Definitions Effective: 12/10/2009

(A) "Advanced energy fund" has the meaning set forth in section 4928.61 of the Revised Code.

(B) "Advanced energy resource" has the meaning set forth in division (A)(34) of section 4928.01 of the Revised Code.

(C) "Alternative energy resource" has the meaning set forth in division (A)(1) of section 4928.64 of the Revised Code.

(D) "Biologically derived methane gas" means landfill methane gas; or gas from the anaerobic digestion of organic materials, including animal waste, municipal wastewater, institutional and industrial organic waste, food waste, yard waste, and agricultural crops and residues.

(E) "Biomass energy" means energy produced from organic material derived from plants or animals and available on a renewable basis, including but not limited to: agricultural crops, tree crops, crop by-products and residues; wood and paper manufacturing waste, including nontreated by-products of the wood manufacturing or pulping process, such as bark, wood chips, sawdust, and lignin in spent pulping liquors; forestry waste and residues; other vegetation waste, including landscape or right-of-way trimmings; algae; food waste; animal wastes and by-products (including fats, oils, greases and manure); biodegradable solid waste; and biologically derived methane gas.

(F) "Clean coal technology" means any technology that removes or has the design capability to remove criteria pollutants and carbon dioxide from an electric generating facility that uses coal as a fuel or feedstock as identified in the control plan requirements in paragraph (C) of rule 4901:1-41-03 of the Administrative Code.

(G) "Co-firing" means simultaneously using multiple fuels in the generation of electricity. In the event of co-firing, the proportion of energy input comprised of a renewable energy resource shall dictate the proportion of electricity output from the facility that can be considered a renewable energy resource.

(H) "Commission" means the public utilities commission of Ohio.

(I) "Deliverable into this state" means that the electricity originates from a facility within a state contiguous to Ohio. It may also include electricity originating from other locations, pending a demonstration that the electricity could be physically delivered to the state.

(J) "Demand response" has the meaning set forth in rule 4901:1-39-01 of the Administrative Code.

(K) "Demand-side management" has the meaning set forth in paragraph (F) of rule 4901:5-5-01 of the Administrative Code.

(L) "Distributed generation" means electricity production that is on-site and is connected to the electricity grid.

(M) "Double-counting" means utilizing renewable energy, renewable energy credits, or energy efficiency savings to do any of the following:

(1) Satisfy multiple Ohio state renewable energy requirements or such requirements for more than one state.

(2) Comply with both the energy efficiency and advanced energy statutory benchmarks.

(3) Support multiple voluntary product offerings

(4) Substantiate multiple marketing claims.

(5) Some combination of these.

(N) "Electric generating facility" means a power plant or other facility where electricity is produced.

(O) "Electric services company" has the meaning set forth in division (A)(9) of section 4928.01 of the Revised Code.

(P) "Electric utility" has the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(Q) "Energy efficiency" has the meaning set forth in rule 4901:1-39-01 of the Administrative Code.

(R) "Energy storage" means a facility or technology that permits the storage of energy for future use as electricity.

(S) "Fuel cell" means a device that uses an electrochemical energy conversion process to produce electricity.

(T) "Geothermal energy" means hot water or steam extracted from geothermal reservoirs in the earth's crust and used for electricity generation..

(U) "Hydroelectric energy" means electricity generated by a hydroelectric facility as defined in division (A)(35) of section 4928.01 of the Revised Code.

(V) "Hydroelectric facility" has the meaning set forth in division (A)(35) of section 4928.01 of the Revised Code.

(W) "Mercantile customer" has the meaning set forth in division (A)(19) of section 4928.01 of the Revised Code.

(X) "MISO" means "Midwest Independent Transmission System Operator, Inc." or any successor regional transmission organization.

(Y) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(Z) "PJM" means "PJM Interconnection, LLC" or any successor regional transmission organization.

(AA) "Placed-in-service" means when a facility or technology becomes operational.

(BB) "Renewable energy credit" means the environmental attributes associated with one megawatt-hour of electricity generated by a renewable energy resource, except for electricity generated by facilities as described in paragraph (E) of rule 4901:1-40-04 of the Administrative Code.

(CC) "Renewable energy resource" has the meaning set forth in division (A)(35) of section 4928.01 of the Revised Code.

(DD) "Solar energy resources" means solar photovoltaic and/or solar thermal resources.

(EE) "Solar photovoltaic" means energy from devices which generate electricity directly from sunlight through the movement of electrons.

(FF) "Solar thermal" means the concentration of the sun's energy, typically through the use of lenses or mirrors, to drive a generator or engine to produce electricity.

(GG) "Solid wastes" has the meaning set forth in section 3734.01 of the Revised Code.

(HH) "Staff" means the commission staff or its authorized representative.

(II) "Standard service offer" means an electric utility offer to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

(JJ) "Wind energy" means electricity generated from wind turbines, windmills, or other technology that converts wind into electricity.

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4901:1-40-02 Purpose and Scope Effective: 12/10/2009

(A) This chapter addresses the implementation of the alternative energy portfolio standard, including the incorporation of renewable energy credits, as detailed in sections 4928.64 and 4928.65 of the Revised Code respectively. Parties affected by these alternative energy portfolio standard rules include all Ohio electric utilities and all electric services companies serving retail electric customers in Ohio. Any entities that do not serve Ohio retail electric customers shall not be required to comply with the terms of the alternative energy portfolio standard.

(B) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

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4901:1-40-03 Requirements Effective: 12/10/209

(A) All electric utilities and affected electric services companies shall ensure that, by the end of the year 2024 and each year thereafter, electricity from alternative energy resources equals at least twenty-five per cent of their retail electric sales in the state.

(1) Up to half of the electricity supplied from alternative energy resources may be generated from advanced energy resources.

(2) At least half of the electricity supplied from alternative energy resources shall be generated from renewable energy resources, including solar energy resources, in accordance with the following annual benchmarks:

Annual benchmarks for alternative energy resources generated from renewable and solar energy resources

By end of year:	Renewable energy resources	Solar energy resources
2009	0.25%	0.004%
2010	0.50%	0.01%
2011	1.0%	0.03%
2012	1.5%	0.06%
2013	2.0%	0.09%

By end of year:	Renewable energy resources	Solar energy resources
2014	2.5%	0.12%
2015	3.5%	0.15%
2016	4.5%	0.18%
2017	5.5%	0.22%
2018	6.5%	0.26%
2019	7.5%	0.30%
2020	8.5%	0.34%
2021	9.5%	0.38%
2022	10.5%	0.42%
2023	11.5%	0.46%
2024 and each year thereafter	12.5%	0.50%

(a) At least half of the annual renewable energy resources, including solar energy resources, shall be met through electricity generated by facilities located in this state. Facilities located in the state shall include a hydroelectric generating facility that is located on a river that is within or bordering this state, and wind turbines located in the state's territorial waters of Lake Erie.

(b) To qualify towards a benchmark, any electricity from renewable energy resources, including solar energy resources, that originates from outside of the state must be shown to be deliverable into this state.

(3) All costs incurred by an electric utility in complying with the requirements of section 4928.64 of the Revised Code, shall be avoidable by any consumer that has exercised choice of electricity supplier, during such time that a customer is served by an electric services company.

(B) The baseline for compliance with the alternative energy resource requirements shall be determined using the following methodologies:

(1) For electric utilities, the baseline shall be computed as an average of the three preceding calendar years of the total annual number of kilowatt-hours of electricity sold under its standard service offer to any and all retail electric customers whose electric load centers are served by that electric utility and are located within the electric utility's certified territory. The calculation of the baseline shall be based upon the average, annual, kilowatt-hour sales reported in that electric utility's three most recent forecast reports or reporting forms.

(2) For electric services companies, the baseline shall be computed as an average of the three preceding calendar years of the total annual number of kilowatt-hours of electricity sold to any and all retail electric consumers served by the company in the state, based upon the kilowatt-hour sales in the electric services company's most recent quarterly market-monitoring reports or reporting forms.

(a) If an electric services company has not been continuously supplying Ohio retail electric customers during the preceding three calendar years, the baseline shall be computed as an average of annual sales data for all calendar years during the preceding three years in which the electric services company was serving retail customers.

(b) For an electric services company with no retail electric sales in the state during the preceding three calendar years, its initial baseline shall consist of a reasonable projection of its retail electric sales in the state for a full calendar year. Subsequent baselines shall consist of actual sales data, computed in a manner consistent with paragraph (B)(2)(a) of this rule.

(3) An electric utility or electric services company may file an application requesting a reduced baseline to reflect new economic growth in its service territory or service area. Any such

application shall include a justification indicating why timely compliance based on the unadjusted baseline is not feasible, a schedule for achieving compliance based on its unadjusted baseline, quantification of a new change in the rate of economic growth, and a methodology for measuring economic activity, including objective measurement parameters and quantification methodologies.

(C) Beginning in the year 2010, each electric utility and electric services company annually shall file a plan for compliance with future annual advanced- and renewable-energy benchmarks, including solar, utilizing at least a ten-year planning horizon. This plan, to be filed by April fifteenth of each year, shall include at least the following items:

(1) Baseline for the current and future calendar years.

(2) Supply portfolio projection, including both generation fleet and power purchases.

(3) A description of the methodology used by the company to evaluate its compliance options.

(4) A discussion of any perceived impediments to achieving compliance with required benchmarks, as well as suggestions for addressing any such impediments.

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4901:1-40-04 Qualified Resources Effective: 12/10/2009

(A) The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the renewable energy resource benchmarks:

(1) Solar photovoltaic or solar thermal energy.

(2) Wind energy.

(3) Hydroelectric energy.

(4) Geothermal energy.

(5) Solid waste energy derived from fractionalization, biological decomposition, or other process that does not principally involve combustion.

(6) Biomass energy.

(7) Energy from a fuel cell.

(8) A storage facility, if it complies with the following requirements:

(a) The electricity used to pump the resource into a storage reservoir must qualify as a renewable energy resource, or the equivalent renewable energy credits are obtained.

(b) The amount of energy that may qualify from a storage facility is the amount of electricity dispatched from the storage facility.

(9) Distributed generation system used by a customer to generate electricity from one of the resources or technologies listed in paragraphs (A)(1) to (A)(8) of this rule.

(10) A renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998.

(B) The following resources or technologies, if they have a placed-in-service date of January 1, 1998, or after, are qualified resources for meeting the advanced energy resource benchmarks:

(1) Any modification to an electric generating facility that increases its generation output without increasing the facility's carbon dioxide emissions (tons per year) in comparison to its actual annual carbon dioxide emissions preceding the modification. In such an instance, it is the incremental increase in generation output that may be quantified and applied toward an advanced energy requirement.

(2) Any distributed generation system, designed primarily to meet the energy needs of the customer's facility that utilizes co-generation of electricity and thermal output simultaneously.

(3) Clean coal technology.

(4) Advanced nuclear energy technology, from:

(a) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission or other later technology.

(b) Significant improvements to existing facilities. In such an instance, it is the incremental increase in generation attributable to the improvement that may be quantified and applied toward an advanced energy requirement. Extension of the life of existing nuclear generation capacity shall not qualify as advanced nuclear energy technology.

(5) Energy from a fuel cell.

(6) Advanced solid waste or construction and demolition debris conversion technology that results in measurable greenhouse gas emission reductions.

(7) Demand-side management and energy efficiency, above and beyond that used to comply with any other regulatory standard or programs.

(C) The following new or existing mercantile customer-sited resources may be qualified resources for meeting electric utilities' annual, renewable- or advanced-energy resource benchmarks, as applicable, provided that it does not constitute double-counting for any other regulatory requirement and that the mercantile customer has committed the resource for integration into the electric utility's demand-response, energy efficiency, or peak-demand reduction programs pursuant to rule 4901:1-39-08 of the Administrative Code.

(1) Renewable energy resources from mercantile customers include the following:

(a) Electric generation equipment that uses a renewable energy resource and is owned or controlled by a mercantile customer.

(b) Any renewable energy resource of the mercantile customer that can be utilized effectively as part of an alternative energy resource plan of an electric utility and would otherwise qualify as a renewable energy resource if it were utilized directly by an electric utility.

(2) Advanced energy resources from mercantile customers include the following:

(a) A resource that improves the relationship between real and reactive power.

(b) A mercantile customer-owned or controlled resource that makes efficient use of waste heat or other thermal capabilities.

(c) Storage technology that allows a mercantile customer more flexibility to modify its demand or load and usage characteristics.

(d) Electric generation equipment owned or controlled by a mercantile customer that uses an advanced energy resource.

(e) Any advanced energy resource of the mercantile customer that can be utilized effectively as part of an advanced energy resource plan of an electric utility and would otherwise qualify as an advanced energy resource if it were utilized directly by an electric utility.

(D) An electric utility or electric services company may use renewable energy credits (REC) to satisfy all or part of a renewable energy resource benchmark, including a solar energy resource benchmark.

(1) To be eligible for use towards satisfying a benchmark, a REC must originate from a facility that meets the definition of a renewable energy resource, including solar energy resources, and be measured by a utility-grade meter in compliance with paragraph B of rule 4901:1-10-05 of the Administrative Code, for facilities with generating capacity of more than six kilowatts. Such facilities could include a mercantile customer-sited resource that is not committed for integration into an electric utility's demand-response, energy efficiency, or peak-demand reduction program pursuant to rule 4901:1-39-08 of the Administrative Code but that otherwise qualifies under the terms of paragraph (A) of this rule.

(2) To use RECs as a means of achieving partial or complete compliance, an electric utility or electric services company must be a registered member in good standing of at least one of the following:

(a) The PJM's generation attributes tracking system.

(b) The MISO's renewable energy tracking system.

(c) Another credible tracking system approved for use by the commission.

(3) A REC may be used for compliance any time in the five calendar years following the date of its initial purchase or acquisition.

(4) Double counting is prohibited.

(5) The RECs must be associated with electricity that was generated no earlier than July 31, 2008.

(E) For a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate principally from biomass energy by June 30, 2013, the number of RECs produced by each megawatt-hour of electricity generated principally from biomass energy shall equal the actual percentage of biomass feedstock heat input used to generate such megawatt-hour multiplied by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code, by the then existing market value of one REC, but such megawatt-hour shall not equal less than one credit.

(F) An entity seeking resource qualification shall file an application for certification of its resources or technologies, upon such forms as may be prescribed by the commission. The application shall include a determination of deliverability to the state in accordance with paragraph (I) of rule 4901:1-40-01 of the Administrative Code.

(1) Any interested person may file a motion to intervene and file comments and objections to any application filed under this rule within twenty days of the date of the filing of the application.

(2) The commission may approve, suspend, or deny an application within sixty days of it being filed. If the commission does not act within sixty days, the application is deemed automatically approved on the sixty-first day after the date filed.

(3) If the commission suspends the application, the applicant shall be notified of the reasons for such suspension and may be directed to furnish additional information. The commission may act to approve or deny a suspended application within ninety days of the date that the application was suspended.

(4) Upon commission approval, the applicant shall receive notification of approval and a numbered certificate where applicable. The commission shall provide this certificate number to the appropriate attribute tracking system.

(5) Representatives of certified facilities must notify the commission within thirty days of any material changes in information previously submitted to the commission during the certification process. Failure to do so may result in revocation of certification status.

(6) Certification of a resource or technology shall not predetermine compliance with annual benchmarks, and does not constitute any commission position regarding cost recovery.

(G) At its discretion, the commission may classify any new technology or additional resource as an advanced- or renewable-energy resource. Any interested person may request a hearing on such classification.

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4901:1-40-05 Annual Status Reports and Compliance Reviews Effective: 12/10/2009

(A) Unless otherwise ordered by the commission, each electric utility and electric services company shall file by April fifteenth of each year, on such forms as may be published by the commission, an annual alternative energy portfolio status report analyzing all activities undertaken in the previous calendar year to demonstrate how the applicable alternative energy portfolio benchmarks and planning requirements have or will be met. Staff shall conduct annual compliance reviews with regard to the benchmarks under the alternative energy portfolio standard.

(1) Beginning in the year 2010, the annual review will include compliance with the most recent applicable renewable- and solar-energy resource benchmark.

(2) Beginning in the year 2025, the annual review will include compliance with the most recent applicable advanced energy resource benchmark.

(3) The annual compliance reviews shall consider any under-compliance an electric utility or electric services company asserts is outside its control, including but not limited to, the following:

(a) Weather-related causes.

(b) Equipment shortages for renewable or advanced energy resources.

(c) Resource shortages for renewable or advanced energy resources.

(B) Any person may file comments regarding the electric utility's or electric services company's alternative energy portfolio status report within thirty days of the filing of such report.

(C) Staff shall review each electric utility's or electric services company's alternative energy portfolio status report and any timely filed comments, and file its findings and recommendations and any proposed modifications thereto.

(D) The commission may schedule a hearing on the alternative energy portfolio status report.

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4901:1-40-06 Force Majeure Effective: 12/10/2009

An electric utility or electric services company may seek a force majeure determination from the commission for all or part of a minimum renewable- or solar-energy benchmark.

(A) A decision on a request for a force majeure determination will be rendered within ninety days of an electric utility or electric services company filing a request for such determination. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) At the time of requesting such a determination from the commission, an electric utility or electric services company shall demonstrate that it pursued all reasonable compliance options including, but not limited to, renewable energy credit (REC) solicitations, REC banking, and long-term contracts.

(2) The request shall include an assessment of the availability of qualified in-state resources, as well as qualified resources within the territories of PJM and the MISO.

(B) If the commission determines that force majeure conditions exist, it may modify that compliance obligation of the electric utility or electric services company, as it considers appropriate to accommodate the finding.

(1) Such modification does not automatically reduce future-year obligations.

(2) The commission retains the right to increase a future year's compliance obligation by the amount of any under compliance in a previous year that is attributed to a force majeure determination.

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4901:1-40-07 Cost Cap Effective: 12/10/2009

(A) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with an advanced energy resource benchmark would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

(E) If the commission makes a determination that a three per cent provision is triggered, the electric utility or electric services company shall comply with each benchmark up to the point that the three per cent increment would be reached for each benchmark.

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4901:1-40-08 Compliance Payments Effective: 12/10/2009

(A) Any electric utility or electric services company that does not achieve an annual renewable energy resource benchmark, including a solar benchmark, shall remit a compliance payment based on the amount of noncompliance rounded up to the next megawatt hour (MWh), unless the commission has identified the existence of force majeure conditions or the commission has determined that the three per cent cost-cap provision would be exceeded in the event of full compliance.

(1) The required payment for noncompliance with any solar energy resource benchmark shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by the per MWh amount in the table below.

Solar energy resources - compliance payment

Year	Payment per MWh
2009	$450
2010 and 2011	$400
2012 and 2013	$350
2014 and 2015	$300
2016 and 2017	$250

2018 and 2019	$200
2020 and 2021	$150
2022 and 2023	$100
2024 and beyond	$50

(2) The required payment for noncompliance with any renewable energy resource benchmark, excluding solar, shall be calculated by quantifying the level of noncompliance, rounded to the next MWh, and multiplying this figure by an amount determined by the commission.

(a) The per MWh payment for renewable energy resources for the year 2009 is forty-five dollars.

(b) Beginning in the year 2010, the per MWh payment for renewable energy resources will be adjusted annually to reflect the annual change to the consumer price index as defined in section 101.27 of the Revised Code. Such adjustment shall be performed by staff no later than June first of each calendar year. This annual adjustment shall be calculated using the following formula:

((CPIYR2/CPIYR1) * current per MWh payment)

(c) In no event shall the compliance payment for renewable energy resources be less than forty-five dollars per MWh.

(3) At least annually, the staff shall conduct a review of the renewable energy resource market, including solar, both within this state and within the regional transmission systems active in the state. The results of this review shall be used to determine if changes to the solar- or renewable-energy compliance payments are warranted, as follows:

(a) The commission may increase compliance payments if needed to ensure that electric utilities and electric services companies are not using the payments in lieu of acquiring or producing energy or RECs from qualified renewable resources, including solar.

(b) Any recommendation to reduce the compliance payments shall be presented to the general assembly.

(B) Any compliance payment shall be submitted to the commission for deposit to the credit of the advanced energy fund. All compliance payments shall be delivered to the commission within thirty days of the imposition of any compliance payment requirement.

(C) Compliance payments shall be subject to such collection and enforcement procedures as apply to the collection of a forfeiture under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code.

(D) Any electric utility or electric services company found to be liable for a compliance payment is prohibited from passing compliance payments on to consumers. In the event that a compliance payment is required, an electric utility or electric services company shall submit an attestation, signed by a company officer or designee, indicating that it will not seek to recover the specific compliance payment from consumers. Such attestation shall be submitted to staff within thirty days of the imposition of any compliance payment requirement.

Effective: 12/10/2009
R.C. 119.032 Review Date(s): 9/30/2013
Promulgated Under: R.C. 111.15
Statutory Authority: R.C. 4901.13, 4905.04, 4905.06, 4928.02, 4928.64
Rule Amplifies: R.C. 4928.64, 101.68, 101.27

4901:1-40-09 Annual Report Effective: 12/10/2009

(A) Pursuant to division (D)(1) of section 4928.64 of the Revised Code, an annual report shall be submitted to the general assembly addressing at least the following topics:

(1) The compliance status of electric utilities and electric services companies with respect to the advanced- and renewable-energy resource benchmarks.

(2) Suggested strategies for electric utility and electric services company compliance.

(3) Suggested strategies for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers:

(a) Available technology.

(b) Costs.

(c) Job creation.

(d) Economic impacts.

(B) The report shall be submitted in accordance with section 101.68 of the Revised Code.

(C) Prior to its submission to the general assembly, the report will be issued for public comment by interested persons for thirty days, unless otherwise ordered by the commission. The process and timeframes for soliciting public comment shall be set by entry of the commission, the legal director, deputy director, or attorney examiner.

Effective: 12/10/2009
R.C. 119.032 Review Date(s): 9/30/2013
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Statutory Authority: R.C. 4901.13, 4905.04, 4905.06, 4928.02, 4928.64, 4928.65
Rule Amplifies: R.C. 4928.64, 4928.65

PUCO CHAPTER 4901:1-41

GREENHOUSE GAS REPORTING AND CARBON DIOXIDE CONTROL

Ohio | Public Utilities Commission

Chapter 4901:1-41
Greenhouse Gas Reporting and Carbon Dioxide Control

4901:1-41-01 Definitions Effective: 12/10/2009

(A) "Carbon dioxide control planning" means the establishment and implementation of a structured, verifiable process including goals, policies, and procedures, to measure carbon dioxide emissions and control options on both a facility and a system-wide scale over five-, ten- and twenty-year periods.

(B) "Commission" means the public utilities commission of Ohio.

(C) "The Climate Registry" means the nonprofit collaboration among North American states, provinces, territories and native sovereign nations, using the website at www.theclimateregistry.org, that sets consistent and transparent standards to calculate, verify, and publicly report greenhouse gas emissions into a single registry..

(D) "Electric generating facility" means an electric generating plant and associated facilities capable of producing electricity of fifty megawatts or larger.

(E) "Greenhouse gas" means the emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and/or sulphur hexafluoride.

(F) "Public utility" means those entities included within the definition of "public utility" set forth in section 4905.02 of the Revised Code, or within the definition of "electric service company" set forth in section 4928.01 of the Revised Code.

R.C. 119.032 Review Date(s): 9/30/2010
Promulgated Under: R.C. 111.15
Statutory Authority: R.C. 4905.04, 4905.06, 4928.02, 4928.68
Rule Amplifies: R.C. 4928.68

4901:1-41-02 Purpose and Scope Effective: 12/10/2009

(A) This chapter provides rules for the reporting of greenhouse gas emissions and carbon dioxide control planning for electric generating facilities within Ohio, pursuant to section 4928.68 of the Revised Code.

(B) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

R.C. 119.032 Review Date(s): 9/30/2010
Promulgated Under: R.C. 111.15
Statutory Authority: R.C. 4905.04, 4905.06, 4928.02, 4928.68
Rule Amplifies: R.C. 4928.68

4901:1-41-03 Greenhouse Gas Reporting and Carbon Dioxide Control Effective: 12/10/2009

(A) Unless otherwise directed by the commission, any public utility owning or operating an electric generating facility within Ohio shall become a participating member in the climate registry and shall report greenhouse gas emissions according to the protocols approved by the climate registry.

(B) Any public utility that owns or operates an electric generating facility within Ohio shall file with the commission by April fifteenth of each calendar year an environmental control plan, including carbon dioxide control planning. A copy of such plan shall also be provided to the director of the Ohio environmental protection agency, or his designee.

(C) The environmental control plan shall include all relevant technical information on the current conditions, goals, and potential actions for resource planning or environmental compliance. Any technology included in this plan, including clean coal, shall be based upon the most current scientific and engineering design capability of any facility or that has been designed to have the capability to control the emissions of criteria pollutants and carbon dioxide within the parameters of economically feasible best technology.

R.C. 119.032 Review Date(s): 9/30/2010
Promulgated Under: R.C. 111.15
Statutory Authority: R.C. 4905.04, 4905.06, 4928.02, 4928.68
Rule Amplifies: R.C. 4928.68

PUCO CHAPTER 4901:5-3

FILING OF LONG-TERM FORECAST REPORTS; FEES

4901:5-3-01 Long-Term Forecast Report Due Dates Effective: 12/10/2009

(A) All electric transmission owners or electric utilities required by section 4935.04 of the Revised Code to file a long-term forecast report must file annually on or before April fifteenth. For years in which their forecast does not show substantial change, the electric transmission owner or the electric utility may file only the forms specified in Chapter 4901:5-5 of the Administrative Code in satisfying the requirements of this rule. In any year that a hearing is required under division (D)(3) of section 4935.04 of the Revised Code, the electric transmission owner or electric utility must file a complete long-term forecast report.

(B) All gas and natural gas distribution companies required by section 4935.04 of the Revised Code to file a long-term forecast report must file annually on or before June first. On alternating years, each gas utility may file only the forms specified in Chapter 4901:5-7 of the Administrative Code in satisfying the requirements of this rule. In any year that a hearing is required under division (D)(3) of section 4935.04 of the Revised Code, the reporting utility must file a complete long-term forecast report.

(C) On or before December thirty-first of each year, the commission shall notify each electric transmission owner or electric utility of the number of copies of its long-term forecast report it shall be required to submit at the next filing. On or before February fifteenth of each year, the commission shall notify each gas or natural gas distribution company of the number of copies of its long-term forecast report it shall be required to submit at the next filing. In the event that no notice is sent by the commission, the company shall submit the same number of copies of the long-term forecast report submitted with the previous year's filing.

(D) Notwithstanding the requirements of paragraphs (A) and (B) of this rule, the commission may grant an extension of the filing deadline for good cause shown.

R.C. 119.032 Review Date(s): 12/1/2010
Promulgated Under: R.C. 111.15
Statutory Authority: R.C. 4901.13, 4935.04
Rule Amplifies: R.C. 4935.04
Prior Effective Dates: 11/20/87, 3/18/88, 1/15/90, 3/24/97, 9/18/00, 5/31/07

4901:5-3-02 Fees Effective: 12/10/2009

(A) Fees for electric transmission owners or electric utilities shall be submitted annually to the commission on or before May first.

(B) Fees for gas and natural gas distribution companies shall be submitted annually to the commission on or before September fifteenth.

(C) All fee payments shall be made by check, payable to "the public utilities commission of Ohio."

(D) The commission shall annually determine the fee each utility must pay, and shall notify each utility as to that amount at least thirty days prior to the date payment is due.

(E) Fees for electric transmission owners or electric utilities will be based on:

(1) For electric transmission owners, the fee shall be two and one-half mills per megawatt hour delivery based upon the energy deliveries for loads connected to the system inside Ohio for the most recent year for which actual data is reported on the most recently filed form FE-T1 column twelve.

(2) For electric utilities, the fee shall be two and one-half mills per megawatt- hour delivery based upon the net energy for load for the most recent year for which actual data is reported on the most recently filed form FE-D1 column eight.

(F) Fees for gas and natural gas distribution companies will be based on two factors:

(1) In-state total number of meters in December of the preceding year, as reported to the commission on form SG-1.

(2) Total in-state sales for the most recent calendar year for which actual data are reported to the commission on the most recently filed form SG-1.

(G) Annual fees for gas and natural gas distribution companies shall be the sum of the following charges:

(1) One hundred mills per meter.

(2) Two hundred ninety-seven mills per million cubic feet.

R.C. 119.032 Review Date(s): 12/1/2010
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Statutory Authority: R.C. 4935.04
Rule Amplifies: R.C. 4935.04
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4901:5-3-03 Calculation of Forecast Rates of Change Effective: 12/10/2009

(A) For the purposes of division (D)(3)(c)(i) of section 4935.04 of the Revised Code, the change in the average annual rate of change in the forecasted electric peak loads or energy delivery shall be calculated by comparing the average annual compound rate of change of the previous year's long-term forecast with the average annual rate of change of the current year's long-term forecast. The average annual compound rate of change shall be calculated as the rate of change occurring between year zero and year ten.

(B) The average annual compound rate of change in electric energy delivery for a given forecast shall be calculated as the rate of change occurring between year zero and year ten. For electric utilities, the rate of change shall be calculated based upon the net energy for load on form FE-D1, column eight.

(C) The average annual compound rate of change in electric peak loads for a given forecast shall be calculated as the rate of change occurring between year zero and year ten. The greater of winter or summer internal load shall be used to determine average annual compound rate of change. For electric utilities, the rate of change shall be based upon the electric utility's forecast of its seasonal peak load demand in Ohio as reported on form FE-D3.

(D) For the purposes of division (D)(3)(c)(i) of section 4935.04 of the Revised Code, the change in the average annual rate of change in the forecasted gas consumption shall be calculated by comparing the average annual compound rate of change of the previous year's long-term forecast with the average annual compound rate of change of the current year's long-term forecast. The average annual compound rate of change shall be calculated as the rate of change occurring between year zero and year ten.

(E) The average annual compound rate of change in gas consumption for a given forecast shall be calculated as the rate of change occurring between year zero and year ten, as reported in the sum of column ten, total consumption, of form FG1-1 plus column four, total volumes transported by respondent for on-system customers, of form FG1-6.

R.C. 119.032 Review Date(s): 12/1/2010
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Statutory Authority: R.C. 4901.13, 4935.04
Rule Amplifies: R.C. 4935.04
Prior Effective Dates: 11/12/78, 10/12/79, 6/1/83, 10/14/85, 11/20/87, 3/24/97, 9/18/00, 5/31/07

PUCO CHAPTER 4901:5-5

ELECTRIC UTILITY FORECAST REPORTS

Ohio | Public Utilities Commission

Chapter 4901:5-5 Electric Utility Forecast Reports

4901:5-5-01 Definitions Effective: 12/10/2009

(A) "ATC" means available transfer capability as defined by the regional reliability organization standards.

(B) "Alternative energy resource" has the meaning set forth in division (A)(1) of section 4928.64 of the Revised Code.

(C) "Available system capability" means the installed capability of all generating units on the utility system plus firm purchases.

(D) "Capability" means the net seasonal demonstrated rating of generating equipment, as defined by the regional reliability organization reliability standards.

(E) "Certified territory" means the service area established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.(F) Demand-side management" means those programs or activities that are designed to modify the magnitude and/or patterns of electricity consumption in a utility's service area by means of equipment installed or actions taken on the customer's premises.

(G) "Electric transmission owner" means the owner of a major utility facility as defined in section 4935.04 of the Revised Code.

(H) "Energy-price relationships" means the calculated or observed effect on peak load, load shape, or energy consumption resulting from changes in the retail price of electricity or other fuels.

(I) "Forecast year," "year of the forecast," or "year zero" means the year in which the forecast is filed.

(J) "Forecast period" means year zero through year ten.

(K) "Integrated operating system" means a group of electric transmission owners or electric utilities who are members of a jointly or commonly operated system as a single entity.

L) "Integrated resource plan" means that plan or program, established by a person subject to the requirements of this chapter, to furnish electric energy services in a cost-effective and reasonable manner consistent with the provision of adequate and reliable service, which gives appropriate consideration to supply- and demand-side resources and transmission or distribution investments for meeting the person's projected demand and energy requirements.

(M) "Internal load" of a system means the summation of the net output of its generators plus the net of interconnection receipts and deliveries.

(N) "Interruptible load" means load that can be curtailed or reduced at the supplier's discretion or in accordance with a contractual agreement

(O) "Load" means the amount of power needed to be delivered at a given point on an electric system.

(P) "Load modification" means the impact of a demand-side management, energy efficiency, demand reduction, price responsive demand, or demand response program designed to influence customers' patterns of electricity use in order to modify the utility's load shape.

(Q) "Load shape" means the distribution of a utility's total electricity demand measured over time, usually expressed as a curve which plots megawatts supplied against time of occurrence, and illustrates the varying magnitude of the load during that time period.

(R) "Native load" of a system means the internal load minus interruptible loads.

(S) "Nonutility generation" means any source of electricity which is interconnected with a utility's system, but is not exclusively owned by an electric utility.

(T) "Peak demand" or "peak load" means the electric transmission owner's or electric utility's maximum sixty-minute integrated clock hour predicted or actual load for the year.

(U) "Price responsive demand" means the predictable response to changes in wholesale electricity prices of electricity demand by consumers who are served at retail rates or prices that can vary based on wholesale electricity prices or market conditions.

(V) "Renewable energy resource" has the meaning set forth in division (A)(35) of section 4928.01 of the Revised Code.

(W) "Reporting person" means any person required to file a long-term forecast report under section 4935.04 of the Revised Code.

(X) "Supply-side resources" mean those resources that directly increase the amount of electricity available for consumption in a utility's certified territory.

(Y) "Transfer capability," means the ability of the transmission owner's system to move power over its system to another interconnected transmission system or distribution utility while meeting all national standard reliability requirements.

(Z) "TTC" means total transfer capacity as defined by the regional reliability organization standards and is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines or paths within the interconnected electric systems.

R.C. 119.032 Review Dates: 12/01/2010
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Rule Amplifies: 4935.04
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4901:5-5-02 Purpose and Scope Effective: 12/10/2009

A) This chapter specifies the reporting requirements for long-term forecast reports filed by electric utilities and transmission owners pursuant to Chapter 4901:5-1 of the Administrative Code.

(B) Unless otherwise directed by the commission, all reports shall be filed using such forms as may be posted on the commission's web site. Such forms may be changed without further commission entry and each reporting person should check the commission's web site to obtain the current forms before filing a report.

(C) The commission may, upon an application or a motion filed by a party, waive any requirement of this chapter, other than a requirement mandated by statute, for good cause shown.

R.C. 119.032 Review Dates: 12/01/2010
Promulgated Under: 111.15
Statutory Authority: 4901.13, 4935.04
Rule Amplifies: 4935.04
Prior Effective Dates:

4901:5-5-03	Forecast Report Requirements for Electric Utilities and Transmission Owners	Effective: 12/10/2009

A) Summary of the long-term forecast report.

The long-term forecast report shall contain a summary describing the electric utility's forecast of loads and the resource plan to meet that load, and shall include at a minimum:

(1) The planning objectives.

(2) A summary of its forecasts of energy and peak load demands and the key assumptions or projections underlying these forecasts.

(3) A description of the process by which the energy and peak load forecasts were developed.

(B) General guidelines. The following guidelines shall be used in the preparation of the forecast:

(1) The forecast must be based upon independent analysis by the reporting electric transmission owner or electric utility.

(2) The forecast may be based on those forecasting methods that yield the most useful results to the electric transmission owner or electric utility.

(3) Where the required data have not been calculated directly, relevant conversion factors shall be displayed.

(C) Special subject areas.

(1) The following matters shall specifically be addressed:

(a) A description of the extent to which the reporting electric transmission owner or electric utility coordinates its load and resource forecasts with those of other systems such as affiliated systems in a holding company group, associated systems in an integrated operating system or other coordinating organizations, or other neighboring systems.

(b) A description of the manner in which such forecasts are coordinated, and any problems experienced in efforts to coordinate forecasts.

(c) A brief description of any polls, surveys, or data-gathering activities used in preparation of the forecast.

(2) No later than six months prior to the required date of submission of the forecast, the commission may supply the reporting electric transmission owner or electric utility:

(a) Copies of appropriate commission or other state documents or public statements that include the state energy policy for consideration in preparation of the forecast.

(b) Such current energy policy changes or deliberations, which, due to their immediate significance, the commission determines to be relevant for specific identification in the forecast (including but not limited to new legislation, regulations, or adjudicatory findings). The reporting person shall provide a discussion of the impacts of such factors and how it has taken these factors into account.

(3) Existing energy efficiency, demand reduction, and demand response programs and policies of the reporting person, which support energy conservation and load modification, shall be described along with an estimate of their impacts on energy and peak demand and supply resources.

(4) Energy-price relationships:

(a) To the extent possible, identify the relationship between price and energy consumption and describe how such changes are accounted for in the forecast.

(b) To the extent possible, specify a demand function that will or can be used to identify the relationship between any dynamic retail prices and peak load, which captures the impact of price responsive demand.

(c) A description of, and justification for, the methodologies employed for determining such energy-price relationships shall be included.

(D) Forecast documentation. The purpose of the documentation section of the report is to permit a thorough review of the forecast methodology and test its validity. The components of the forecast documentation include:

(1) A description of the forecast methodology employed, including:

(a) Overall methodological framework chosen.

(b) Specific analytical techniques used, their purpose, and the forecast component to which they are applied.

(c) The manner in which specific techniques are related in producing the forecast.

(d) Where statistical techniques have been used:

(i) All relevant equations and data.

(ii) The size of the standard error of the estimate, and the size of the forecasting error, associated with each relevant forecasting model equation, this information shall be included for each forecast at the bottom of forms FE-D1 to FE-D6.

(iii) A description of the technique.

(iv) The reason for choosing the technique.

(v) Identification of significant computer software used.

(e) An explanation of how controllable and interruptible loads are forecasted and how they are treated in the total forecast.

(f) An identification of load factors or other relevant conversion factors and a description of how they are used within the forecast.

(g) Where the methodology for any sector has changed significantly from the previous year, a discussion of the rationale for the change.

(2) Assumptions and special information. The reporting person shall:

(a) For each significant assumption made in preparing the forecasts, include a discussion of the basis for the assumption and the impact it has on the forecast results. Give sources of the assumption if other than the reporting person.

(b) Identify special information bearing on the forecast (e.g., the existence of a major planned industrial expansion program in the area of service or other need determined on a regional basis).

(3) Database documentation. The responsibilities of the reporting person with regard to its forecast database are as follows:

(a) The reporting person shall provide or cause to be provided:

(i) A brief description of all data sets used in making the forecast, both internal and external, input and output, and a citation to the sources.

(ii) The reasons for the selection of the specific database used.

(iii) A clear identification of any significant adjustments made to raw data in order to adapt them for use in the forecast, including, to the extent practicable:

(a) The nature of the adjustment made.

(b) The basis for the adjustment made.

(c) The magnitude of the adjustment.

(b) If a hearing is to be held on the forecast in the current forecast year, the reporting person shall provide to the commission in electronic formats or other medium as the commission directs, all data series, both input and output, raw and adjusted, and model equations used in the preparation of the forecast.

(c) The reporting person shall provide to the commission, on request:

(i) Copies of all data sets used in making the forecasts, including both raw and adjusted data, input and output data, and complete descriptions of any mathematical, technical, statistical, or other model used in preparing the data.

(ii) A narrative explaining the data sets and any adjustments made with the data to adapt it for use in the forecast.

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4901:5-5-04 Forecasts for Electric Transmission Owners Effective: 12/10/2009

(A) General guidelines. The electric transmission owner shall provide or cause to be provided data on the use of its transmission lines and facilities.

(1) The forecast shall include data on all existing transmission lines and associated facilities of one hundred twenty-five kilovolts (kV) and above as defined by the commission, for year zero to year ten.

(2) The forecast shall include data on all planned transmission lines and associated facilities of one hundred twenty-five kilovolts (kV) and above as well as substantial planned additions to, and replacement of existing facilities, as defined by the commission for year zero to year ten.

(3) The reporting electric transmission owner shall be prepared to supply to the commission on demand, additional data and maps of transmission lines and facilities.

(B) Transmission energy data and peak demand forecast forms. The electric transmission owner's forecast shall be submitted in an electronic form prescribed by the commission or its staff.

(1) Electric transmission owners shall file energy delivery forecast (megawatt hours/year) data: Actual and forecast as shown on form FE-T1. The electric transmission owner shall indicate the total energy it received from all generating sources connected to their transmission system within Ohio as well as the total energy received from all generating sources connected to their system. They shall indicate the total energy received at interconnections with other electric transmission owners within Ohio as well as the total energy received from all its interconnections. The electric transmission owner shall report the total energy deliveries to interconnections within Ohio as well as to all its interconnections. The electric transmission owner shall report the total energy deliveries for loads within Ohio as well as to all load deliveries.

(2) Electric transmission owners shall file system seasonal peak load demand forecasts: Actual and forecast system peak demand levels for summer and winter seasons as displayed on form FE-T2, covering both native and internal loads, as defined in the form.

(3) Monthly data of energy and peak loads. The electric transmission owner shall specify in detail the methodology employed to produce monthly forecasts of energy and peak load for the current year and one year in the future. The reporting electric transmission owner shall provide or cause to be provided monthly information as required on the following forms:

(a) "Total monthly energy forecast" forecast information concerning monthly energy forecasts shall be provided for two years on form FE-T3.

(b) "Monthly internal peak load forecast" forecast information concerning monthly peak load forecasts shall be provided for two years on form FE-T4.

(c) "Monthly energy transaction" the reporting electric transmission owner shall provide or cause to be provided monthly data on all energy received and delivered for the twelve months of the most recent year for which actual data is reported on the forms FE-T5 and FE-T6:

(i) On form FE-T5 part A, the electric transmission owner shall provide or cause to be provided monthly data on all energy received under firm contract and nonfirm contract:

(a) From power plants directly connected to their transmission system.

(b) From other sources.

(c) The total energy received from all sources for the month.

(ii) On form FE-T5 part B, the electric transmission owner shall provide or cause to be provided monthly data on energy delivered under firm and nonfirm contract for the total system and for delivery points located in Ohio:

(a) The amount of power delivered to affiliated electric utilities.

(b) The amount of power delivered to other nonaffiliated investor-owned electric utilities.

(c) The amount of power delivered to cooperatively owned electric utilities.

(d) The amount of power delivered to municipally owned electric utilities.

(e) The amount of power delivered to federal and state electric agencies.

(f) The amount of power delivered for nondistribution service.

(g) The total amount of power delivered.

(iii) On form FE-T5 part C, the electric transmission owner shall provide or cause to be provided monthly data on system losses and/or unaccounted for energy by firm and nonfirm transmission service.

(4) The reporting electric transmission owner shall provide the following data on the operating conditions of transmission owner's system at the time of the system's monthly peak for each month during the most recent year on form FE-T6:

(a) The date and time of peak.

(b) The peak MWs.

(c) Any scheduled transmission outages on the system.

(d) Any unscheduled transmission outages on the system.

(e) Any emergency operating procedures in effect.

(C) The existing transmission system.

(1) The reporting electric transmission owner shall provide or cause to be provided a brief narrative description of the existing electric transmission system and identify any transmission constraints and critical contingencies with and without the power transfers to the neighboring companies detailed in forms FE-T7 and FE-T8:

(a) A summary of the characteristics of existing transmission lines shall be shown as indicated in form FE-T7, characteristics of existing transmission lines.

(b) A separate listing of substations for each line included in form FE-T7 shall be shown as indicated in form FE-T8, summary of existing substations.

(2) Each reporting electric transmission owner shall provide or cause to be provided maps of its electric transmission system as follows:

(a) One schematic map of the transmission network.

(b) A map showing the actual, physical routing of the transmission lines, geographic landmarks, major metropolitan areas, and the location of substations and generating plants, interconnects with distribution, and interconnections with other electric transmission owners.

(c) Two copies of the map described in paragraph (C)(2)(b) of this rule, for commission use, on a 1:250,000 scale. The electric transmission owners may jointly provide one set of maps to meet this requirement. Participation in the commission's joint mapping project will meet this requirement.

(D) The planned transmission system. The reporting electric transmission owner shall provide or cause to be provided a detailed narrative description of the planned electric transmission and identify any transmission constraints and critical contingencies with and without the power transfers to the neighboring companies and a description of the plans for development of facilities for years zero through ten as follows:

(1) Specifications of planned transmission lines shall be provided on form FE-T9, specifications of planned electric transmission lines for:

(a) New lines requiring new rights-of-way.

(b) Lines in which changes of capacity, either in terms of current, voltage, or both, are scheduled to take place.

(c) Other changes in transmission lines or rights-of-way, which would be considered as substantial additions, as defined in rule 4906-1-02 of the Administrative Code.

(2) A listing of all proposed substations shall be provided in form FE-T10, summary of proposed substations.

(3) The transmission forecast shall include maps of the planned transmission system as follows:

(a) An overlay to each of the maps required in paragraph (C) of this rule showing the planned transmission lines, substation, and generating plants as they will tie into the existing system; planned lines shall be shown and identified as such and keyed into form FE-T9, to provide as complete a picture of the system as is possible. Combined maps showing both existing and proposed facilities may be substituted for the overlays. Where planning horizons make it impractical to comply fully with the data requirements of this rule, as many data as are available shall be provided along with the estimated date on which additional data will be available.

(b) Two copies of the above overlay, for commission use, on a scale of 1:250,000. The electric transmission owners may jointly provide one set of overlays to meet this requirement. Participation in the commission's joint mapping project will meet this requirement.

(E) Substantiation of the planned transmission system. The reporting electric transmission owner shall submit a substantiation of transmission development plans, including:

(1) Description and transcription diagrams of the base case load flow studies of the transmission owner's transmission system in Ohio, one for the current year and one as projected either three or five years into the future, and provide base case load flow studies on computer disks in PSSE or PSLF format along with transcription diagrams for the base cases.

(2) A tabulation of and transcription diagrams for a representative number of contingency cases studied along with a brief statements concerning the results.

(3) Analysis of proposed solutions to problems identified in paragraph (E)(2) of this rule.

(4) Adequacy of the electric transmission owner's transmission system to withstand natural disasters and overload conditions.

(5) Analysis of the electric transmission owner's transmission system to permit power interchange with neighboring systems.

(6) A diagram showing the electric transmission owner's import and export transfer capabilities and identifying the limiting element(s) during each season of the reporting period. In addition, the reporting electric transmission owner will provide a listing of transmission loading relief (TLR) procedures called during the last two seasons for which actual data are available. That listing may include only those TLRs called as a result of a transmission limit on the reporting electric transmission owner's transmission system. For each TLR event, the listing shall include the maximum level, and the duration at the maximum level, and the magnitude (in MW) of the power curtailments.

(7) A description of any studies regarding transmission system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading, and low voltage, and for improving access to alternative energy resources.

(8) A switching diagram of the transmission network.

(F) Regional and bulk power requirements.

To avoid the inefficiencies associated with having each electric transmission owner report this data, the electric transmission owners may have the regional transmission system operator submit a single report on their behalf. This information shall be provided as soon as it becomes available. Data provided to the commission concerning the electric transmission owner's existing and planned bulk power transmission system (two hundred thirty kV and above) shall include the following:

(1) The most recent regional power existing facilities and an authorized map.

(2) A plan on the bulk power transmission network of the region in service (total certified territory of the companies in the region including out-of-state certified territories) at the time of the report, including interfaces with adjoining regions.

(3) Regional transmission system power interchange matrix.

(4) A transmission diagram and a summary of the load flow base case studies of the bulk power network of the region as it now exists at the time of reporting.

(5) A plan of the bulk power transmission network of the region (including interties with adjoining regions) and the general routing of facilities committed or tentatively projected for service within ten years, including identification of principal substations, operating voltages, and projected in-service dates.

(6) A list and diagram showing transmission constrains of the bulk power transmission network, including interconnections.

(G) To the extent that information sought in this rule contains critical energy infrastructure, the reporting person shall provide such information to the commission's staff but redact all such information before filing in the case docket.

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4901:5-5-05 Energy and Demand Forecasts for Electric Utilities Effective: 12/10/2009

(A) General guidelines.

(1) The reporting person shall provide or cause to be provided data on the use of the electric utility's distribution lines and facilities.

(2) The reporting person shall specify in detail the methodology employed to produce monthly forecasts of energy and peak load for the current year and one year in the future.

(3) The reporting person shall, upon request, supply to the commission with additional data and maps of distribution lines and facilities.

(B) Distribution energy data and peak demand forecast forms. The distribution forecast shall be submitted in an electronic form prescribed by the commission or its staff.

(1) Each electric utility shall file a certified territory energy forecast (megawatt-hours/year). Each electric utility operating in Ohio shall furnish completed sets of FE-D1 and FE-D2 forms:

(a) FE-D1 shall contain data for only the Ohio portion of the reporting electric utility's total certified territory.

(b) Electric utilities that are members of an integrated operating system and operated on a system basis shall also file FE-D2 for the integrated system.

(2) Each electric utility shall file Ohio and system seasonal peak load demand forecasts: Actual and forecast system peak demand levels for summer and winter seasons as displayed on forms FE-D3 and FE-D4, as follows:

(a) FE-D3 shall contain data for only the Ohio portion of the reporting electric utility's total certified territory.

(b) Electric utilities that are members of an integrated operating system and operated on a system basis shall also file form FE-D4 for the integrated system.

(3) Monthly forecasts of energy and peak loads. The electric utility shall specify in detail the methodology employed to produce monthly forecasts of energy peak load and resources for the current year and one year in the future. The reporting electric utility shall provide or cause to be provided monthly information as required on the following forms:

(a) From FE-D5, monthly net energy for load forecast.

(b) Form FE-D6, monthly native and internal peak load forecasts.

(C) Substantiation of the planned distribution system. The reporting electric utility shall submit a substantiation of distribution development plans, including:

(1) Load flow or other system analysis by voltage class of the electric utility's distribution system performance in Ohio that identifies and considers each of the following:

(a) Any thermal overloading of distribution circuits and equipment.

(b) Any voltage variations on distribution circuits that do not comply with the current version of the American National Standard Institute (ANSI) standard C84.1, electric power systems and equipment voltage ratings or standard as later amended.

(2) Analysis and consideration of proposed solutions to problems identified in paragraph (C)(1) of this rule.

(3) Adequacy of the electric utility distribution system to withstand natural disasters and overload conditions.

(4) Analysis and consideration of any studies regarding distribution system improvement, including, but not limited to, any studies of the potential for reducing line losses, thermal loading and low voltage or any other problems, and for improving access to alternative resources.

(5) A switching diagram of circuits less than one hundred twenty-five kV that are not radial.

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4901:5-5-06 Resource Plans Effective: 12/10/2009

(A) As part of the long-term forecast report filed pursuant to rule 4901:5-3-01 of the Administrative Code, an electric utility shall include a resource plan as defined in rule 4901:5-5-01 of the Administrative Code, which shall contain a narrative discussion and analysis of the following:

(1) Anticipated technological changes which may be expected to influence the reporting person's generation mix, use of energy efficiency and peak-demand reduction programs, availability of fuels, type of generation, use of alternative energy resources pursuant to section 4928.64 of the Revised Code or techniques used to store energy for peak use.

(2) The availability and potential development of alternative energy resources pursuant to section 4928.64 of the Revised Code for generating electricity.

(3) Research, development, and demonstration efforts relating to alternative energy resources, including expenditure information and description of specific investigations, and the nature and timing of anticipated results of these investigations.

(4) The impact of environmental regulations on generating capacity, cost, and reliability, including precise quantitative estimates and/or historical data pursuant to division (B)(2)(b) and/or (B)(2)(c) of section 4928.143 of the Revised Code.

(5) Textual material not specifically required but of importance to the resource forecast of the reporting utility may be included in the appropriate section.

(6) Electricity resource forecast forms. In addition to the foregoing discussion and analysis, an electric utility shall include the following forms as published by the commission:

(a) Form FE-R1, "Monthly Forecast of Electric Utility's Ohio Service Area Peak Load and Resources Dedicated to Meet Ohio Service Area Peak Load." Forecast information concerning monthly loads and resources shall be provided for two years on form FE-R1.

(b) Form FE-R2, "Monthly Forecast of System Peak Load and Resources Dedicated to Meet System Peak Load." Forecast information concerning monthly loads and resources shall be provided for two years on form FE-R2.

(c) Existing system description. The reporting person shall provide the existing electric system generating capability both inside and outside Ohio in summary form as indicated in form FE-R3: "Summary of Existing Electric Generation Facilities for the System."

(d) Long-term forecast requirements. The reporting person shall provide a ten-year forecast which shall identify the electricity resource options (including purchased power) expected to be needed to meet forecast system load levels, as identified in the peak load demand forecast, on the following forms:

(i) Form FE-R4: "Actual Generating Capability Dedicated to Meet Ohio Peak Load."

(ii) Form FE-R5: "Projected Generating Capability Changes To Meet Ohio Peak Load." A summary and reconciliation of the information given in form FE-R10 shall be provided by the completion of form FE-R5.

(iii) Form FE-R6: "Electric Utility's Actual and Forecast Ohio Peak Load and Resources Dedicated to Meet Ohio Peak Load." Actual and forecast information concerning summer seasonal loads and resources shall be provided for years minus five through ten on form FE-R6.

(iv) Form FE-R7: "Actual and Forecast System Peak Load and Resources Dedicated to Meet System Peak Load." Actual and forecast information concerning summer seasonal loads and resources shall be provided for years minus five through ten on form FE-R7.

(v) Form FE-R8: "Electric Utility's Actual and Forecast Ohio Peak Load and Resources Dedicated to Meet Ohio Peak Load." Actual and forecast information concerning winter seasonal loads and resources shall be provided for years minus five through ten on form FE-R8.

(vi) Form FE-R9: "Actual and Forecast System Peak Load and Resources Dedicated to Meet System Peak Load." Actual and forecast information concerning winter seasonal loads and resources shall be provided for years minus five through ten on form FE-R9.

(e) Plans for development of facilities in the forecast period. Information regarding new generating capacity shall be provided for each planned facility on form FE-R10: "Specifications of Planned Electric Generation Facilities."

(i) All information on facilities which will commence operating during the forecast period and facilities on which construction will commence during the forecast period shall be displayed.

(ii) Each applicable facility shall be keyed to the capacity increases summarized in form FE-R5, indicating the amount and timing of additional generating capability provided.

(B) In the long-term forecast report filed pursuant to rule 4901:5-3-01 of the Administrative Code, the following must be filed in the forecast year prior to any filing for an allowance under sections 4928.143(B)(2)(b) and (c) of the Revised Code:

(1) Existing generating system description.

(a) The reporting person shall provide a brief summary narrative of the existing electric generating system. If a hearing is to be held on the forecast in the current year, the reporting person shall submit to the commission with its long-term forecast report, the anticipated operating, maintenance, and fuel expense of each unit for each year of the forecast period. The commission may make exceptions to this paragraph for good cause.

(b) A summary of the pooling, mutual assistance, and all agreements for purchasing from and selling power and energy to other utilities or nonutility generators, including costs and amounts, shall be provided.

(2) Need for additional electricity resource options. The reporting person shall describe the procedure followed in determining the need for additional electricity resource options. All major factors shall be discussed, including but not limited to:

(a) System load profile.

(b) Maintenance requirements of existing and planned units.

(c) Number of units, unit size, and availability of existing and planned units.

(d) Forecast uncertainty.

(e) Electricity resource option uncertainty with respect to cost, availability, commercial in-service dates, and performance.

(f) Lead times for construction or implementation of planned electricity resource options.

(g) Power interchange with other electric systems, including consideration of the ability to buy and sell power.

(h) Price-responsive demand and price elasticity due to the implementation of time-differentiated pricing options and assessments of the value of lost load.

(i) Regulatory climate.

(j) Reliability criteria, including a discussion and analysis of the reporting person's reliability criteria and factors influencing their selection, including, but not limited to:

(i) Reliability measures used and factors including the selection.

(ii) Engineering analysis performed.

(iii) Economic analysis performed.

(iv) Any judgments applied.

(3) Resource plan.

(a) This paragraph shall include the electric utility's projected mix of resource options to meet the base case projection of peak demand and total energy requirements.

(b) A discussion of the electric utility's projected system reliability shall be presented. It shall include:

(i) A discussion of the future adequacy of the electric utility's projected system in both the short- and long-term.

(ii) A discussion of the future adequacy of fuel supplies in both the short- and long-term. Additionally, the reporting person shall provide, for the forecast period, a description of its overall fuel procurement policies and procedures. A description of the system's fuel requirements, the system's geographic source of fuel supply, and the percentage of fuel supply under contract shall be included.

(c) The electric utility shall demonstrate the cost-effectiveness of the plan through a comparison over the ten-year forecast horizon of the revenue requirement and rate impacts of the selected plan and alternative plans evaluated. The selection of the plan shall demonstrate adequate consideration of the risks, reliability, and uncertainties associated with the person's selected plan and alternative plans, and of other factors the electric utility deems appropriate.

(d) The methodology for arriving at the plan must be fully explained and described. The description must be sufficiently explicit, detailed and complete to allow the commission and other knowledgeable parties to understand how the assessment was conducted. This description shall also include:

(i) A general discussion of the decision-making process, criteria, and standards employed by the electric utility as it relates to the development of the resource plan.

(ii) A discussion of how the plan is consistent with the overall planning objectives of paragraph (A) of rule 4901:5-5-03 of the Administrative Code.

(iii) A discussion of key assumptions and judgments used in development of the resource plan.

(e) The reporting person shall provide information sufficient for the commission to determine the reasonableness of the resource plan, including:

(i) The adequacy, reliability, and cost-effectiveness of the plan.

(ii) Whether the methodology used to develop the plan evaluates demand-side management programs and nonelectric utility generation on both sides of the meter in a manner consistent with electric utility's generation and other electricity resource options. At a minimum, the total resource cost test as defined in rule 4901:1-39-01 of the Administrative Code, should be used to determine the cost-effectiveness of demand-side management programs.

(iii) Whether the plan gives adequate consideration to the following factors:

(a) Potential rate and customer bill impacts of the plan.

(b) Environmental impacts of the plan and their associated costs.

(c) Other significant economic impacts and their associated costs.

(d) Impacts of the plan on the financial status of the company.

(e) Other strategic considerations including flexibility, diversity, the size and lead time of commitments, and lost opportunities for investment.

(f) Equity among customer classes.

(g) The impacts of the plan over time.

(h) Such other matters the commission considers appropriate.

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