BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technology, Resources, and Climate Regulations, and Review of Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code, Pursuant to Chapter 4928.66, Revised Code, as Amended by Amended Substitute Senate Bill No. 221.	)	Case No. 08-888-EL-ORD

OPINION AND ORDER

The Commission finds:

BACKGROUND:

On July 31, 2008, Amended Substitute Senate Bill No. 221 (SB 221) was enacted to, among other things, substantially revise Chapter 4928 of the Revised Code, in addressing energy efficiency and alternative energy resources, renewable energy credits, clean coal technology, and environmental regulations.

On August 20, 2008, the Commission issued an entry requesting comments from interested persons to assist in the review of new rules and rule changes proposed by the Commission's staff in response to SB 221. Staff proposed modifications to the current forecast rules contained in Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 of the Ohio Administrative Code (O.A.C.), and the creation of three new O.A.C. chapters:

4901:1-39	Energy Efficiency and Demand Reduction Benchmarks
4901:1-40	Alternative Energy Portfolio Standard
4901:1-41	Greenhouse Gas Reporting and Carbon Dioxide Control Planning.

Comments and/or reply comments to the staff proposal were filed by the following parties:

American Ag Fuels, a producer of biodiesel fuel within Ohio

The American Electric Power operating companies, Columbus Southern Power Company and Ohio Power Company (AEP)

American Municipal Power-Ohio, Inc. (AMP-Ohio)

The American Wind Energy Association, Wind on the Wires, Ohio Advanced Energy, and Environment Ohio (Wind Advocates), a coalition of wind power and energy trade associations, and an environmental advocacy organization.

APX, Inc., an infrastructure provider for environmental and energy markets in renewable energy and greenhouse gases

Buckeye Power, Inc.

The city of Cleveland, Ohio

The Climate Registry, an international nonprofit organization for environmental reporting programs

Constellation NewEnergy, Inc.; Direct Energy Services, LLC; and Integrys Energy Services, Inc. (Competitive Suppliers)

The Council of Smaller Enterprises (COSE), a support organization for small businesses in northeast Ohio

The Dayton Power and Light Company (DP&L)

Duke Energy Ohio, Inc. (Duke)

East Ohio Gas Company, dba Dominion East Ohio

EnerNOC, Inc., a demand response, energy efficiency, and energy management services provider in the United States and Canada

Environment Ohio, a citizen-based statewide environmental group

The FirstEnergy Corporation operating companies, Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company (FirstEnergy)

Global Energy, Inc., a developer, owner, and operator of advanced energy facilities with specific focus on gasification of solid feedstock materials such as Ohio coal and biomass based renewables.

The Great Lakes Energy Development Task Force of Cuyahoga County, Ohio

Greenfield Steam & Electric Co., an Ohio-based solar energy system manufacturer

The city of Hamilton, Ohio

Jon A. Husted, Speaker of the Ohio House of Representatives

Industrial Energy Users-Ohio (IEU)

Interstate Gas Supply, Inc.

The Kroger Company, Inc. (Kroger)

LS Power Associates, L.P., a group of developers, owners, operators, and investors of independent power generation in the United States

The Mid-Ohio Regional Planning Commission and the Center for Energy & Environment (MORPC)

New Generation Biofuels (New Generation)

Norton Energy Storage, Ltd. (Norton)

Nucor Steel Marion, Inc. (Nucor)

The Ohio Consumer and Environmental Advocates (OCEA), a consortium that includes the Office of the Ohio Consumers Counsel, city of Toledo, Ohio Partners for Affordable Energy, Ohio Interfaith Power and Light, Appalachian People's Action Coalition, Citizen Power, Northwest Ohio Aggregation Coalition, Edgemont Neighborhood Coalition of Dayton, Natural Resources Defense Council, the Northeast Ohio Public Energy Council, Sierra Club - Ohio Chapter, Environment Ohio, Midwest Energy Efficiency Alliance, Sun Edison, Northeast Ohio Public Energy Council, AARP-Ohio, Citizens for Fair Utility Rates, Neighborhood Environmental Coalition, Cleveland Housing Network, Empowerment Center for Greater Cleveland, Counsel for Citizens Coalition, United Clevelanders Against Poverty, Communities United for Action, and Ohio Farmers Union.

The Ohio Energy Group (OEG), a coalition of industrial customers

The Ohio Environmental Council (OEC), a nonprofit, charitable organization comprised of a network of over 100 affiliated group members, seeking to promote a healthier environment for Ohioans

The Ohio Farm Bureau Federation (Farm Bureau)

Ohio Fuel Cell Coalition

PJM Environmental Information Services, Inc.

Rolls-Royce Fuel Cell Systems

The Sierra Club

The United Steelworkers, District 1

Vertus Technologies Industrial LLC (Vertus)

DISCUSSION:

The August 20, 2008, entry issued in this case included staff's proposed modifications to the gas forecasting rules in Chapter 4901:5-7, O.A.C., to accommodate the inclusion of a new separate rule listing all the defined terms to be used in the gas forecast chapter. Currently, Rule 4901:5-1-01, O.A.C., defines terms to be used in all four forecasting chapters, including Chapter 4901:5-7, O.A.C. To comport with the Commission's rulemaking practices, such as the inclusion of all definitions in the first rule of each chapter, and a purpose and scope statement in the second rule, staff also proposed modifications to Chapters 4901:5-1 and 4901:5-3, which generally govern long-term forecast reports and the associated filing requirements for any person required to file a long-term forecast report under Section 4935.04, Revised Code. Although the proposed revisions to these forecasting chapters were served upon all gas and natural gas companies, we are concerned that the proposed modifications may not have been sufficiently reviewed by all industry participants as the instant case is only designated by the electric industry case type. Moreover, these chapters are due to be reviewed in 2010 pursuant to Section 119.032, Revised Code. Accordingly, except for the correction of two O.A.C. references that are incorrect in the existing rules, we will postpone our consideration of modifications to the forecasting chapters that would impact the gas and natural gas companies until our five-year review that is scheduled to occur next year.

Therefore, we will limit changes in this proceeding to those required by SB 221. Additional suggestions or modifications may be considered in next year's proceeding, which will include both gas and electric forecasting chapters.

Before addressing the individual chapters and rules, we would like to thank all participants for the development of these rules and the insightful comments and reply comments submitted in this proceeding. In some instances, we will be making substantial changes to the structure and content of the rules proposed by staff, often at the suggestion of the comments that we have received. However, due to the volume of materials and time constraints, we will not attempt to address every issue or suggestion raised. In certain instances, we may have incorporated suggested changes into our rules or addressed concerns without expressly acknowledging the source of the suggestion in this order. To the extent that a comment is not specifically addressed in this order or incorporated into our adopted rules, it has been rejected.

Given the extremely hasty process for rulemaking imposed by statutory requirements, OCEA suggested that this Commission not rely on the usual five-year review schedule mandated by Section 119.032, Revised Code, but instead establish an expedited schedule of annual and biennial proceedings for which the parties might better plan and devote the resources necessary for the complex review of these matters. We appreciate the concerns of all stakeholders in the development of regulations and processes to implement the mandates of SB 221 while balancing the interests of the ratepayers, the electric utilities, industry participants, and the public.

While we recognize that these rules may require review and modification prior to the normal five-year review schedule, particularly with respect to recent amendments to SB 221, we believe it would be premature to establish a schedule for the next review of these materials at this point. However, as discussed below, we also recognize the need for further development and consideration of more detailed subjects, such as measurement and verification standards. In addition, we expect the resources of this Commission, the electric utilities, and all stakeholders will be better devoted to the development of the assessment potential and program planning requirements adopted in the new rules added to Chapter 4901:1-39. Accordingly, our focus in this proceeding is the adoption of a flexible framework that meets the statutory obligations imposed upon the electric utilities and this Commission, while also encouraging the development of new technologies or processes to maximize public benefits. In many instances, we believe the use of workshops, collaboratives, or other forums may provide better options than a continuous rulemaking proceeding for dealing with these matters.

With respect to each of the chapters, the Commission has adopted a uniform format of listing all definitions applicable to the chapter in the first rule, while the second rule contains a statement of purpose and scope. The Commission is revising staff's proposed rules to modify or include in the purpose and scope rule of each chapter a provision that allows the Commission to waive a rule for good cause shown. Some of the comments opposed staff's proposed rule, stating that the Commission cannot create a rule that allows the agency to waive statutory requirements imposed on the electric utilities or the Commission itself by SB 221. Although a modified rule waiver provision is included in each chapter, we agree that the Commission cannot have a rule or issue any order that is inconsistent with any statute.

Chapter 4901:1-39 Energy Efficiency and Demand Reduction Benchmarks

Many comments criticized proposed Chapter 4901:1-39 as being confusing and incomplete, and suggested numerous changes to the rule structure and substance to clarify the Commission's process for compliance with SB 221 requirements under Section 4928.66, Revised Code. OCEA and OEC both offered substantial rewrites and additions to this chapter. OEC argues that it would make more sense to present the requirements for benchmark reports before setting out the procedure for the review and approval of the reports, and suggests switching the order of Rules 4901:1-39-03 and 4901:1-39-04[1] to reorder the rules in a fashion consistent with the format proposed in Chapter 4901:1-40 for evaluating compliance with benchmarks governing the resource mix of power supply portfolios.

OCEA proposes a rewrite of Rule 39-04 to cover specific aspects of the annual benchmark review process, and new rules that focus on the forward-looking energy efficiency and peak-demand reduction program planning process, evaluation, measurement, and verification requirements, and the reporting of past activities, which contains parts of the staff-proposed Rule 39-03 on the filing and review of a benchmark report.

We agree that a rewrite of this chapter is necessary. As an initial matter, we have adopted the title "Energy Efficiency and Demand Reduction Programs" for this chapter as opposed to "Energy Efficiency and Demand Reduction Benchmarks." This title more accurately reflects that Section 4928.66, Revised Code, mandates that each electric utility implement energy efficiency and peak demand reduction programs to meet statutory benchmarks.

The rules we are adopting through this order incorporate substantial changes in both structure and substance as suggested in the comments and reply comments. These changes reflect our statutory obligations to foster programs that will promote and encourage conservation of energy in accordance with Section 4905.70, Revised Code, and to encourage innovation and market access for cost-effective demand-side retail electric

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1 Hereafter, the Commission will refer to specific rules contained in Chapters 4901:1-39, 4901:1-40, and 4901:1-41 by their last four numbers instead of the full code section being discussed in each subsection of the order.

service under Section 4928.02(D), Revised Code. As the energy efficiency benchmarks represent the minimum energy efficiency savings required by Section 4928.66(A)(1)(a), Revised Code, and the substitution of cost-effective energy efficiency for retail electric service is, by definition, more cost-effective for consumers, these rules are designed to *require electric utilities to deploy all cost-effective energy efficiency measures.*

The six proposed rules are being revised and expanded to eight rules to reflect a focus on the program planning and review process. As a result, word-for-word comparisons may not be helpful in many instances, particularly with the proposed Rule 39-03: "Filing and review of the benchmark report," and proposed Rule 39-04: "Benchmark report requirements," which are being eliminated in favor of four new rules:

39-03: Program planning requirements.
39-04: Program portfolio plan and filing requirements
39-05: Benchmark and annual status reports
39-06: Review of annual reports and issuance of the Commission verification report

As a result, proposed Rule 39-05: "Recovery mechanism," and proposed Rule 39-06: "Commitment for integration by mercantile customers," have been moved to Rules 39-07 and 39-08, respectively.

With regard to the suggestions of an independent collaborative serving in the role of program administrator for demand-side management (DSM) programs, we note that Section 4928.66, Revised Code, places the responsibility of implementing programs on the electric utilities. While we believe that the use of third-party administrators may be appropriate in some cases,[2] and that the participation of stakeholders will play a crucial role in the success of an electric utility's compliance with SB 221 mandates, we do not believe the suggested shift of administrative duties would be appropriate without further consideration. This Commission has fostered the establishment of such groups in past proceedings, and we expressly encourage stakeholder collaboration in new Rules 39-02, 39-03(D), and 39-04(C)(2), but we do not believe it would be appropriate to delegate an electric utility's responsibilities to such a group at this time.

The comments also advocate adopting specific protocols, such as the Total Resource Cost Test as defined in the California Standard Practice Manual, for the purpose of ensuring that programs are cost effective. In response, we are adopting definitions for "cost effective" and "total resource cost test" in paragraphs (G) and (W) of new Rule 39-01,

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2 *See, e.g., In the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Case No. 08-935-EL-SSO, *Second Opinion and Order* (March 25, 2009) at 13-14, 18-19.

as well as including new requirements for electric utilities to ensure cost-effective program portfolios under Rule 39-04(B).

In addition, OCEA and others urge that energy efficiency programs be made available to all customer classes. This Commission expects the utilities and stakeholders to suggest a broad array of programs to all customer classes in order to achieve the statutory benchmarks, and we have expressly included "equity among customer classes" as a criteria in assessing program potential under new Rule 39-03(B)(6). However, we also note that programs directed at certain customer classes may offer cost and benefit advantages over programs directed at other customer classes. We will weigh and balance these issues as we review the program plans and portfolios in accordance with new Rule 39-04.

Many of the comments also criticize the proposed Chapter 4901:1-39 for appearing to delegate various Commission responsibilities to its staff by failing to expressly incorporate Commission approval. OEC suggests that the benchmark review process work in the same manner as a general rate or GCR case, under which staff conducts an investigation of the electric utility's benchmark report and issues a staff report, to which interested parties, including the electric utility, would have the right to file objections. Such objections would frame the issues in the case, and a hearing would be held upon the issues raised by the objections after providing the parties the opportunity to engage in discovery and to file testimony in support of their positions. If no objections are filed, the Commission would proceed directly to order. Under either scenario, OEC points out that it is the Commission which must ultimately issue an order determining whether the electric utility has complied with the benchmarks if, for no other reason, because under staff-proposed Rule 39-05(A), the approval of the benchmark report is condition precedent to an application by the electric utility for cost recovery.

New Rule 39-04(E) assures that there will be a hearing on the planned portfolio of programs offered by an electric utility. It also assures that the process will be transparent, and that intervenors will have the opportunity to participate and to conduct discovery. Likewise, new Rule 39-06 provides for intervenor participation in the annual review of the electric utility portfolio status reports and an opportunity for input in the new annual Commission verification report required by Section 4928.66(B), Revised Code..

With respect to Chapter 4901:1-39, FirstEnergy criticizes the proposed rules for failing to clarify that improvements to transmission infrastructure owned and operated by an electric utility affiliate, such as American Transmission Systems, Incorporated, a FirstEnergy affiliate, qualify as an energy efficiency program, either on a stand-alone basis or as part of an electric utility program to reduce line losses under Section 4928.66(A)(2)(d), Revised Code. FirstEnergy notes the absence of any conflicting authority and argues that line-loss improvements to third-party transmission assets represent true reductions in energy production for the same usage at the customer level, and also offer one of the best values for energy efficiency. FirstEnergy contends that such loss reductions directly benefit customers through lower transmission rates passed through to retail customers, and indirectly through lower emission and resource costs for generation to meet customer demand.

We note that Section 4928.66(A)(2)(d), Revised Code, specifically includes transmission infrastructure improvements that reduce line losses as appropriate means of achieving energy efficiency benchmarks. We also note that Section 4928.66(A)(1)(a) and (b), Revised Code, require an electric utility to implement programs to meet the energy savings and peak demand reduction benchmarks. Any lack of specific mention in either the proposed or the final rules does not change the law. Transmission infrastructure improvements count. We further note that measuring and verifying net line-loss reductions will require documentation. In this regard, we recognize the need for an efficient and transparent process to adopt and publish Commission-approved guidelines of recognized industry standards, protocols, and best practices to be used by stakeholders in the measurement and verification of energy efficiency programs, and we intend to select an appropriate forum to address these matters in the near future.

4901:1-39-01 Definitions:

Several comments criticize some of staff's proposed definitions as failing to reflect the legislative intent or specific meanings within the context of their usage in SB 221. Others noted that certain terms appear throughout Chapter 4901:1-39 but were not expressly defined in the proposed Rule 39-01, while other terms are used interchangeably even though they have substantially different meanings or are used in a manner inconsistent with the meaning commonly ascribed by the industry. We agree with some of these criticisms and have modified this chapter to use terms consistently and have expanded the number of definitions so that each term's meaning is clear.

AEP recommends using a definition for "demand response" based on language developed by the United States Demand Response Coordinating Committee to mean "providing electricity customers in both retail and wholesale markets with a choice whereby they can respond to dynamic or time-based prices or other types of incentives by reducing and/or shifting usage, particularly during peak periods, such that demand modifications can address issues such as pricing, reliability, emergency response, and infrastructure planning, operation, and deferral."

Kroger recommends that this definition include any "change in the customer's behavior or a change in customer owned or operated assets that effects [sic] the quality and/or timing of the electricity consumed as a result of price signals or other incentives."

Nucor suggests that "demand response" should be expanded to include all interruptible programs. OEC contends Nucor's definition appears to confuse the concept of energy savings (i.e., reducing total kWh consumption) with the concept of "demand reduction" (i.e., reducing the kW of demand experienced at a particular point in time.)

We are revising this definition in Rule 39-01(H) to simplify and more broadly capture the concept for application in this chapter.

Duke criticizes the proposed definition of "energy efficiency" as being vague and giving no direction on how the term would be measured. AEP recommends using a definition based on that used by the United States Department of Energy to reflect a reduction of electricity consumption while retaining comparable functionality for which the electric service is being used:

> "Energy efficiency" means programs or measures that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs or measures reduce overall electricity consumption (reported in megawatt hours) often without explicit consideration for the timing of the program-induced savings. Such savings are generally achieved by substituting technologically advanced equipment to produce the same level content of the useful output from a process, device, or system divided by the energy input into that process, device, or system.

FirstEnergy suggests a different definition:

> "Energy efficiency" means programs or measures that reduce or manage 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.

Kroger requests that the proposed definition of "energy efficiency" be clarified by eliminating the term "energy content" since, Kroger contends, there is no consistent, practical, and verifiable way to measure energy content. Instead, Kroger suggests the term be defined as "the useful output from a process, device, or system divided by the energy input into that process, devise or system."

MORPC suggests that "energy efficiency" should be defined as "means, programs or measures that reduce or manage 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."

However, Nucor suggests that "energy efficiency" include any production process that uses recycled materials for the majority of its raw materials, as such process uses less energy. Nucor's proposal is opposed by OEC and OCEA, which argue that the use of recycled materials, by Nucor, does not achieve the purposes of SB 221 to encourage electric utility and customer-sited efficiency investments to reduce the long-run cost of service. They contend that electric utility customers should not be required to assist funding measures where the associated payback period is such that the measure would have been undertaken in any event simply because it makes economic sense to do so. OCEA indicates that Nucor's suggestion might be appropriate if a facility could utilize recycling as a method to reduce the energy intensity of its processes in a manner that could be evaluated under appropriate protocols.

The term "energy efficiency" evokes an intuitive, common sense understanding among most parties, although a solid technical definition is elusive. Many of the parties rely upon the U.S. Department of Energy's website description of the term for their suggestions. Those definitions refer to programs or activities aimed at reducing energy usage while maintaining the quality and quantity of goods and/or services derived from an energy using device or process. No technical definition is given. The Energy Information Agency (EIA) declares, "Most of what is defined as energy efficiency is actually energy intensity. Energy intensity is the ratio of energy consumption to some measure of demand for energy services—what we call a demand indicator."[3] The EIA suggests that the more critical issue is how to measure energy intensity as a surrogate for energy efficiency.[4]

We will revise the definition of "energy efficiency" in Rule 39-01(J) to eliminate the use of "energy content" and to provide a simple, but appropriate definition, based on the one suggested by FirstEnergy. It will now read as follows:

> "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.

Nucor states that the definition of "peak demand reduction" should make explicit reference to interruptible rates in order to ensure that such rates are properly recognized as peak-demand reduction mechanisms. Further, Nucor believes that the definition should establish that, for a customer participating in a peak-demand reduction program or rate, the customer's demand reduction should be measured with reference to the customer's peak billing demand, rather than some other approach, such as customer's average demand. Kroger concurs with Nucor's suggestion and further recommends that the Commission identify specific hourly ranges in the day, as well as months of the year, and days in those months, that would constitute peak periods.

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3 See "Energy Efficiency – Definition" at http://www.eia.doe.gov/emeu/efficiency/definition.htm

4 See "Energy Efficiency Measurement" at http://www.eia.doe.gov/emeu/efficiency/measure_discussion.htm

OEC states that the proposed definition of "peak demand reduction" does not correspond with the way the term is typically used in the industry. It suggests that the language be refined to clarify the distinction between peak-shifting strategies, which are properly part of the peak-demand reduction toolkit, and energy efficiency efforts designed to reduce overall consumption, which are subject to separate requirements.

The Commission has decided to eliminate this definition but we have included this term by reference to statutory provisions in the new definitions for "peak-demand baseline" and "peak-demand benchmark" in Rule 39-01(P) and (Q).

The definition for "renewable energy credit" is also being eliminated as it is not used in our revised Chapter 4901:1-39, but is used in Chapter 4901:1-40, and thus, will be discussed below.

The comments also contained many suggestions for new terms to be defined in this chapter. As previously noted, the proposed third and fourth rules for this chapter were substantially rewritten and expanded into four separate rules, largely at the suggestion of the comments filed in this case, with new definitions being added for 17 new terms. Our revisions to Chapter 4901:1-39 focus on program planning and development, in a continuous, transparent process that encourages stakeholder participation. In revising this chapter, we have incorporated suggestions for adopting the new definitions for "energy baseline" and "energy benchmark" with respect to both energy efficiency and peak-demand reduction levels, as well as specific definitions for "program" and "measure" to help clarify our intent in applying these expanded rules. We are also adopting definitions to describe the portfolio of programs to be developed and reviewed under the revised or new Rules 39-03 through 39-09. Many of these new definitions, such as "achievable potential," "committed savings," "economic potential," "market transformation," and "technical potential," are future-looking or planning-related terms, while others, such as "nonenergy benefits," "total resource cost test," and "verified savings," have been added to address measurement and verification issues. In addition, we are including the term "independent program evaluator" to provide for the third-party monitoring and verification of program results and evaluation.

4901:1-39-02 Purpose and scope

This rule is being rewritten to more clearly reflect the development of programs necessary to meet the energy efficiency and peak-demand reduction goals of Section 4928.66, Revised Code, including the participation of stakeholders in implementing such programs.

With regard to proposed Rule 39-02, Kroger asserts that an electric utility should not receive credit or benefit from a mercantile customer's investment in energy efficiency or demand reduction that has occurred, or will be made in the future, irrespective of the electric utility's initiatives. IEU-Ohio counters that the results of customer-sited energy efficiency and demand response programs will be reflected in an electric utility's actual sales and peak demand level, irrespective of whether such capabilities are committed to the electric utility. These concerns are more appropriately considered in our review of Rule 39-06, Commitment for integration by mercantile customers, below.

4901:1-39-03 Filing and review of the benchmark report

As noted above, the revised rules attached to this order restructure and substantially revise staff's proposed Rules 39-03 and 39-04 to incorporate many of the suggestions made in the comments. New Rule 39-03, "Program planning requirements," and Rule 39-04, "Program portfolio plan and filing requirements," are forward-looking and designed to focus on the planning and building of programs in a transparent process that encourages stakeholder participation. New Rule 39-05, "Benchmark and annual status reports," and Rule 39-07, "Review of annual reports and issuance of the Commission verification report," incorporate but substantially revise staff's proposed rules pertaining to the statutory requirements under Sections 4928.66(B) and (C), Revised Code.

We believe this restructuring and additional content will more clearly distinguish between requirements relating to reporting, verification, and program design activities, and the process for the review and Commission approval of the SB 221 requirements and reporting obligations.

Duke asserts that the annual benchmark report filing requirement contained in proposed Rule 39-03(A) is unnecessarily burdensome and suggests that the reporting period be increased to every two years. OEC requests that the benchmark report be filed in a docket separate and apart from the long-term forecast report, to facilitate a separate, rigorous review and approval process in which all interested parties are permitted to participate. OEC also objected to the lack of any express provision for Commission review, implying that the proposed rule would leave the determination of benchmark compliance solely up to the Commission's staff.

We first note that the annual benchmark verification process is mandated by statute and culminates in a report to be published by this Commission pursuant to Section 4928.66(B), Revised Code. Moreover, we are adopting new Rules 39-03, "Program planning requirements" and 39-04, "Program portfolio plan and filing requirements," largely based on suggestions by OCEA and OEC, to address the initial assessment of the potential for energy efficiency and peak-demand reduction programs, the development of an electric utility's portfolio of such programs, and the hearing process to allow stakeholder involvement and the transparent review of these programs. New Rule 39-05, "Benchmark and annual status reports," and Rule 39-06, "Review of annual reports and issuance of the Commission verification report," incorporate but substantially revise staff's proposed rules pertaining to the statutory requirements under Sections 4928.66(B) and (C), Revised Code.

Revised Rule 39-05 now requires an electric utility to file an initial benchmark report within 60 days of the effective date of these rules, and an annual program portfolio status report beginning April 15, 2010. These annual compliance filings will be reviewed under the detailed process in new Rule 39-06, and will be used as the basis for the annual verification report that is required to be published by the Commission pursuant to Section 4928.66(B), Revised Code.

With regard to other comments focusing on staff's proposed Rule 39-03, Duke also raises the issue of whether the statutory benchmarks are to be calculated using a fixed base period of 2006-2008, or a rolling average of the three most recent years. This issue is discussed at length under Rule 39-04 as well as Rule 40-03(B), below.

Nucor recommends that an opportunity for discovery be incorporated into proposed Rule 39-03(B), and that the time period for parties to file comments on the report be extended to 60 days. The new rules we are adopting in this order substantially revise our review and hearing processes for both forward-looking program portfolio planning in new Rule 39-04 and the compliance status report under new Rule 39-06. Both rules anticipate active participation by stakeholders in these proceedings and do not preclude the granting of additional time for good cause shown. However, we find it unnecessary to specifically include special discovery periods as suggested by Nucor.

FirstEnergy suggests that the use of "sales reductions" in proposed Rule 39-03(C) be replaced with "achieved energy savings" to mirror the statutory language used in Section 4928.66(A)(1)(a), Revised Code. We agree and have reflected the proposed language in the corresponding Rule 39-05(C)(1).

OEC asserts that proposed Rule 39-03(C) is flawed because the verbiage doesn't match the scope of the subject matter to be investigated by the staff, and does not include a requirement that staff perform audits to verify claimed energy savings and peak-demand reductions, notwithstanding that Rule 4901:1-38-04(D), which was recently adopted in Case No. 08-777-EL-ORD, clearly contemplates that such audits will be conducted. As in its comments in that case, OEC again recommends that the Commission consider retaining a qualified independent third party to assist staff in conducting such audits in view of the scope of the work that will be required and the logistical constraints that will arise due to the fact that all electric utilities are required to file their benchmark reports on the same date. OEC notes the procedure in Rule 4901:1-14-07-D, O.A.C., for engagement of third-party management performance auditors for natural gas companies, and suggests including similar language in this rule to give the Commission the option of using a third-party auditor in a particular case.

We agree with OEC's comments and have included in Rule 39-05(C)(2)(b) a new requirement for an independent program evaluator, as defined in Rule 39-01(L), who will be hired by the electric utility but work solely at the direction of staff.

OEC criticizes the proposed Rule 39-03(D) for failing to allow any party, other than the electric utility, an opportunity to be heard should they disagree with the staff's findings and recommendations. OEC notes that the proposed rule does not even guarantee the electric utility the right to be heard, because the proposed rule does not expressly require that a electric utility's request for hearing be granted by the Commission. Moreover, OEC objects to the failure to specify any procedure for Commission adoption or rejection of the staff's findings, and the lack of any procedures or public notice requirements if the electric utility's request for a hearing is granted. OEC maintains that this process violates Section 4928.66(C), Revised Code, requirements that the Commission provide notice and the opportunity for hearing with respect to benchmark reports.

The new hearing process set forth in new Rule 39-06 expressly includes provisions to address these concerns, although we would also note that a failure to include any statutory duty in these rules does not relieve the Commission from such requirement.

4901:1-39-04 Benchmark report requirements:

As noted above, the structure and content of proposed Rule 39-04 has been substantially revised and incorporated in new Rule 39-05, "Benchmark and annual status reports," and Rule 39-06, "Review of annual reports and issuance of the Commission verification report."

AEP objects to the inclusion of "all actions considered" in Rule 39-04(A)(3) and "all plans for meeting future benchmarks" in Rule 39-04(A)(4), as being overbroad and burdensome. DP&L suggests that the term "calendar" be inserted in Rule 39-04(A)(1) to clarify that the baseline calculation will use the current calendar year, and that "considered" in Rule 39-04(A)(3) be changed to "evaluated" to reflect the inclusion of potential alternatives seriously evaluated by the electric utility. FirstEnergy advocates simply deleting "considered and" from Rule 39-04(A)(3).

OCEA disagrees with the electric utilities' suggestions, arguing that there must be transparency in the evaluation process, and that failure to consider potentially cost effective measures or programs may lead to improper screening if rejected measures or programs are not reported.

The Commission is sensitive to the need to strike a balance between conducting meaningful and structured planning prior to program implementation and generating overly burdensome reporting requirements. We believe we have struck the appropriate balance in Rule 39-03 which requires electric utilities to begin with the broadest view of possible energy efficiency programs (those with technical potential) and focus on those with the greater likelihood of successful implementation (achievable potential).

New Rule 39-03(C) also includes the reporting of "promising measures" that were considered but not found to be cost-effective or achievable, but which show promise for future deployment in order to open the door to enhancing the cost-effectiveness of measures in the future.

DP&L requests clarification that the baseline period for measuring energy savings under Rule 39-04(B)(1) or peak demand reduction under Rule 39-04(B)(2) is the average of the kilowatt hours purchased or the highest coincident peaks in the preceding three years (2006 through 2008), rather than a "rolling average" that changes the three-year base period each year. The electric utilities argue that the use of a rolling average would result in a compounding effect which would, over time, make the targets impossible to achieve. DP&L provides an example that indicates that by year 2025, the effective savings requirement is closer to 39 percent rather than the 22.2 percent required by law. In the alternative, DP&L suggests that the Commission could use a rolling three-year period but make adjustments to eliminate the compounding effect.

OEC does not object to the use of either a fixed base period or an adjusted rolling average period to eliminate the compounding effect. OCEA, however, disputes DP&L's assertion that, over time, targets based on rolling averages would become impossible to achieve. OCEA observes that DP&L's example assumes no load growth. OCEA contends that load growth in Ohio was recently estimated to average three-quarters of a percent for 2008-2025, and if such load growth were to be factored in, the compound effect would be drastically reduced. Therefore, OCEA recommends that the energy efficiency baseline be defined as a rolling three-year average, responsive to actual changes in demand through 2025. In like manner, OCEA objects to DP&L's alternative recommendation to eliminate the effects of the prior year energy efficiency savings from the prior year forecasts.

As noted below, the issue of the correct three-year baseline period also occurs in Chapter 40 under proposed Rule 40-03(B). The issue is whether the period to be used in calculating the baseline should be 2006 through 2008 (the three years prior to January 1, 2009), or a "rolling average" under which the three years used to calculate the base period would change each year. Section 4928.66(A)(2)(a), Revised Code, provides:

> The baseline for energy savings under division (A)(1)(a) of this section shall be the average of the total kilowatt hours the electric distribution utility sold in the preceding three calendar years, and the baseline for a peak demand reduction under division (A)(1)(b) of this section shall be the average peak demand on the utility in the preceding three calendar years, except that the commission may reduce either baseline to adjust for new economic growth in the utility's certified territory.

The Commission finds that the use of a "rolling average" is the most reasonable interpretation, consistent with the goals of SB 221, although an electric utility would not be precluded from requesting reasonable adjustments at the time it files its report.[5]

DP&L asserts that the electric utilities who are members of PJM should use the peak demand set by PJM for billing purposes in determining the appropriate baseline. FirstEnergy also suggests that baseline for peak demand reduction in Rule 39-04(B)(2) be defined as the average of the three coincident peaks from the hourly integrated peak demand coincident with the peak of the transmission owner's control area peak from the past three calendar years. We note the statute specifies the use of the electric utility's peak demand, and we can find no statutory support for using a transmission owner's control area peak demand.

DP&L also objects to the second sentence of staff proposed Rule 39-04(B)(4), asserting that the exhaustion standard for amendments to the baseline are unduly restrictive and inconsistent with Section 4928.66(A)(2)(b), Revised Code, which only requires that the Commission find that the electric utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond the electric utility's reasonable control. DP&L suggests the exhaustion standard would prove impossible for an electric utility to meet and limit the Commission's flexibility to permit reasonable amendments consistent with the public interest. As with Rule 39-04(A)(3), AEP and FirstEnergy object to the term "considered" in Rule 39-04(B)(5), and assert that the reporting of all actions considered, in addition to those actually taken, would be unnecessary, ambiguous, and unduly burdensome to determine, track, and record. This issue is resolved by Rule 39-05(F), in which we have added the word "reasonable" to describe compliance options.

With respect to Rule 39-04(B)(5)(a), we will clarify for Duke that reporting of customer-sited or customer-committed projects are to be included with those programs offered by the electric utility. This issue is addressed in new Rule 39-05(C)(2)(a). An electric utility shall include in its program portfolio status report all reductions counted toward the benchmark, which result from energy efficiency improvements, demand response or demand reduction projects implemented by mercantile customers and committed to the electric utility.

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5 The Commission is aware of U.S. Environmental Protection Agency authority, Congressional proposals and international negotiations that could lead to requirements that utilities significantly reduce carbon dioxide emissions. In the event such requirements take effect, energy efficiency programs will be among the most cost-effective compliance options. Any application for a baseline adjustment should take into consideration potential long-term cost and compliance implications.

FirstEnergy requests that Rule 39-04(B)(5)(b) be clarified by adding that the measurements and verification "may include, but are not limited to, the methods listed" or that "each of the methods listed may be used, but not all are required." Duke also requests clarification on the requirements or compliance methodology to be used for Rule 39-04(B)(5)(c), while DP&L and FirstEnergy suggest that this provision be deleted entirely, arguing that the U.S. Environmental Protection Agency's (USEPA) portfolio manager database is designed to be used as a consumer tool rather than a measurements standard.

The Commission has removed the specific directive concerning the USEPA's portfolio manager database as inappropriate for inclusion in a formal rule at this time. However, we expect the electric utilities to explore participation in this initiative, and make recommendations to the Commission as to what would be required for utilities to automate the process of entering customer data before 2010 as part of each program portfolio plan.

FirstEnergy urges that the ten-year projection of projects to be included in the benchmark report in Rule 39-04(B)(6) be shortened to a five-year reporting period, updated annually, as being far more meaningful to better ensure foresight and apprise interested parties. AEP advocates deleting both the ten-year projection of projects and the five-year action plan with budgets, as being unsupported by statutory authority, unduly burdensome, and of little actual value. OCEA disagrees with AEP in that the benchmarking reporting requirements integrate with the long-term forecast reports (LTFR) and integrated resource plan (IRP) requirements in Chapters 4901:5-1, 4901:5-3, and 4901:5-5, and ensure that Ohio's electric utilities are taking the energy efficiency portfolio standard as serious as the planning for a major generation source. OCEA argues that it is not possible to accurately reflect growth in demand and need for new generation if reductions in demand are not concurrently accounted for.

As noted above, the Commission has adopted a three-year energy efficiency planning cycle with an opportunity for annual modifications under new Rules 39-04(A), 39-05(C)(2)(c), and 39-06(B). In addition, compliance and integrating resource plan reviews will be done on an annual basis. We find these periods to be the most appropriate in balancing the need to establish energy efficiency initiatives in Ohio with the burdens placed on all stakeholders.

With respect to Rule 39-04(B)(7), Duke and DP&L object to the inclusion of the "market valuation" provision in the electric utility's benchmark report assessment of demand reduction potential and energy efficiency resources. The utilities complain that such market valuations would be speculative, and Duke suggests that any market potential study should not be required more often than every five years. OCEA suggests that a market potential study can be co-funded by the distribution utilities to estimate the potential for demand response and energy efficiency, but need not be performed every year as it is rare for the market to change significantly from one year to the next.

As previously described, this section has been replaced by the planning process in Rule 39-03 to more clearly express the Commission's planning expectations. We have specifically included a provision in Rule 39-03(A) to allow utilities to collaborate and co-fund their assessments of potential energy efficiency and peak-demand reduction opportunities on a broader geographic basis than their service areas.

AEP, DP&L and FirstEnergy suggest the addition of a new section in Rule 39-04(B)(8) to expressly allow the banking of over compliance with the energy efficiency and peak demand reduction targets to be used in future years to meet benchmarks. The utilities argue that such a provision would encourage aggressive implementation, and eliminate any incentive for minimal compliance strategies. FirstEnergy also contends that a new provision should be added, stating that customer-cited initiatives that occurred before 2009 will count toward the energy efficiency and peak demand benchmarks. OCEA urges that DP&L's proposed banking language should be rejected or modified because of the nature of peak demand reductions. OCEA argues that an electric utility can bank energy efficiency reductions (and demand reductions that come from an energy efficiency measure) but not nonenergy efficiency derived demand reductions because peak demand reductions that are intended to meet the three-year average benchmark are specific to a point in time (an electric utility's annual peak hour or hours).

We agree that banking of energy efficiency is appropriate to further the state's policies and to meet state standards, and have included an express provision in new Rule 05(E). We cannot agree, however, that such banking can be applied or would further state goals with respect to peak-demand reductions.

We note that Section 4928.66(A)(2)(a), Revised Code, states that the commission may reduce either baseline to adjust for new economic growth in the utility's service territory. We expect that any baseline adjustments made to account for economic growth typically will be temporary, and will address circumstances in which unanticipated increases in the overall rate of growth have made full compliance infeasible. We also expect that any adjustments will account not only for positive economic growth, but also negative economic growth. This is clearly pertinent to the economic conditions that have developed since SB 221 went into effect.

We do not anticipate approving electric utilities meeting their benchmarks on the basis of lower kWh sales owing to economic declines in their service territories. Sections 4928.66(A)(1)(a) and (b), Revised Code, require that electric utility energy efficiency programs and peak demand reduction programs are to be used to achieve the energy savings and demand reduction benchmarks. New Rule 39-05(B) states that, to the extent approved by the Commission, normalization of the utility's baselines for weather and for changes in numbers of customers, sales, and peak demand that are outside of the utility's control shall be consistently applied from year to year. Thus, if an electric utility expects to file for a reduction of its baseline in future years due to unanticipated economic growth, we believe it is appropriate for consistency sake to recognize any unanticipated negative economic growth in its service territory, and propose a corresponding negative reduction in its baseline.

AEP objects to the second sentence of proposed Rule 39-04(C) as being an unlawful delegation to the Commission's staff of the Commission's responsibility to determine compliance with Section 4928.66(A)(1), Revised Code, particularly if parties are deprived of due process in the development of standards used to measure statutory obligations. AEP recommends that the proposed rule adopt generally accepted industry standards, such as the 2001 International Performance Measurement and Verification Protocol (IPMVP) standards. At a minimum, AEP seeks clarification that any staff-issued guidelines will not be binding upon the Commission. DP&L also recommends that the second sentence of proposed Rule 39-04(C) be modified to require that any guidelines for program measurement and verification be reviewed and approved by the Commission. FirstEnergy does not object to this provision so long as it is given sufficient notice and time to comply with published guidelines.

As previously discussed, the intent of these rules was not to delegate this Commission's policy decisions to our staff. Revised rule 39-04 establishes a separate review process for the three-year portfolio planning cycle, while new Rules 39-05 and 39-06 contain the annual compliance reporting requirements and review processes. With respect to measurement and verification guidelines, we anticipate the selection of an appropriate forum and process in the near future, but in any event, we intend that such guidelines would be established with some form of Commission approval.

The electric utilities also object to proposed Rule 39-04(C)(1) as reaching beyond any statutory authority, conflicting with the counting of mercantile customer programs under Section 4928.66(A)(2)(c), Revised Code, and being contrary to sound public policy by discouraging electric utility support for legislation, city-sponsored programs, or building code proposals aimed at enhancing energy efficiency. Duke queries whether Commission-approved programs (such as replacement of incandescent with compact florescent lighting) will not count if they occurred before the new standards go into effect. The utilities suggest that there is no reason to exclude past achievements, and contend that this provision would make the utilities subject to future penalties based upon future changes in federal standards.

OCEA argues that electric utilities should not get credit for energy savings for customer-installed measures, appliances, or equipment that are mandated by law. OEC and OCEA assert that the intent of SB 221 is to spur investment in energy efficiency measures that would not otherwise be undertaken. They recommend that the savings for any measures implemented by the utilities or mercantile customers that exceed energy codes or other mandatory standards be counted for the reasonable lifetimes of the facilities in question, but in no instance should credit be given to a measure that merely matches what the electric utility is otherwise required by law to do.

We have changed the provision of proposed Rule 39-04(C)(1) which is now incorporated in new Rule 39-05(D) to prohibit only the counting of those measures that are subject to energy performance standards required by law, including those embodied in the Energy Independence and Security Act of 2007. We see no reason to credit electric utilities for benefits of measures that would have happened regardless of their efforts. Under the new rule, the replacement of incandescent lighting with compact florescent lighting program would count now, but not after such measures become required under the Energy Independence and Security Act of 2007

FirstEnergy also proposes that a new provision be added to clarify that affiliated electric utilities may use a total Ohio benchmark, rather than being forced to comply with company-specific targets and reporting. We find no statutory support for this suggestion. The energy efficiency program requirements of Section 4928.66, Revised Code, expressly apply to electric distribution utilities. We can find no provision that would allow the benchmarks to be met on a consolidated basis.

4901:1-39-05 Recovery mechanism:

Before specifically addressing the comments on Rule 39-05, we note that this rule will be renumbered as Rule 39-07 in the attached rules.

DP&L and FirstEnergy assert that there is no statutory authority for the conditioning of program cost recovery under proposed Rule 39-05(A) upon the approval of the electric utility's long-term forecast and benchmark reports. The electric utilities also argue that the provision would create an unlawful regulatory structure that would require an electric utility to initiate programs to meet targets that will soon be in effect, but would delay any recovery to some future time or even disallow recovery if a benchmark report is disallowed or a target is narrowly missed. DP&L also argues that the proposed rule is invalid because it would diminish the electric utility's right of recovery under Section 4928.143(D), Revised Code.

OCEA objects to the proposed elimination of approval of the electric utility's long-term forecast and benchmark reports as a prerequisite of cost recovery. OCEA argues that the LTFR review is the proper planning venue for resource plans, and recommends that a comprehensive IRP be filed by all Ohio electric utilities every year. OCEA contends that cost recovery for new generation sources or for long-term power purchase contracts identified by utilities in their electricity security plans (ESP) should not be approved absent a demonstration that such resources are least-cost and reasonable risk resources as determined in the LTFR process, and result in compliance with benchmarks under SB 221. Given the expedited nature of the various electric utility ESP cases, OCEA argues that approval of those plans should not commit Ohio ratepayers to long-term resource acquisitions without the benefit of review of an electric utility's forecast and IRP requirements under Chapters 4901:5-1, 4901:5-3, and 4901:5-5.

New Rule 39-07(A) addresses these concerns by conditioning recovery upon approval of the electric utility's program portfolio plan under new Rule 39-04, rather than the LTFR and the benchmark report. We believe this resolution provides sufficient review to protect Ohio ratepayers while minimizing the delay in recovery and thereby encouraging investment in energy efficiency and peak-demand reduction programs consistent with the intent of SB 221. Any such recovery will be subject to annual reconciliation under new Rule 39-07(A).

New Rule 39-07(A) also clarifies that rate adjustment mechanisms must established pursuant applicable ratemaking statutes and procedures. In addition to traditional rate case proceedings, recovery could be provided through a revenue decoupling mechanism that aligns the electric utility's financial interests with helping their customers use energy more efficiently under Sections 4928.143(B)(2)(h) or 4928.66(D), Revised Code. To the extent not otherwise authorized, an electric utility could seek recovery of peak demand reduction and energy efficiency program costs under Section 4905.31(E), Revised Code.

FirstEnergy contends that the term "potential" should be changed to "actual" with respect to the shared savings referenced in Rule 39-05(A). FirstEnergy asserts that the amount of shared savings will be known, so that no potential amounts should be used for the calculation. We have modified our new Rule 07(A) to eliminate the word "potential," but we also note the change in the process under Chapter 4901:1-39 should result in recovery upon plan approval, subject to reconciliation in the Commission's verification of energy savings and peak demand reductions.

The electric utilities also object to the wording of Rule 39-05(A)(1), as creating an unnecessary potential for future litigation over the recovery of transmission and distribution infrastructure investments that reduce line losses but that also enhance reliability. DP&L asserts that the proposed rule is inconsistent with Section 4928.143(B)(2)(h), Revised Code, which allows an electric utility to request single issue ratemaking treatment for infrastructure improvements while expressly requiring the Commission to examine the reliability of the electric utility's distribution system in approving such request. FirstEnergy contends that recovery should not be dependent upon the purpose for which the investment is made. DP&L suggests that the phrase "if such investments are found to reduce line losses" be substituted for the proposed language: "limited to the portion of those investments that are attributable to energy efficiency purposes as opposed to reliability or market purposes."

OCEA disagrees with the electric utilities' proposed revision, and recommends that all transmission and distribution investments be recovered in a traditional distribution rate case or, as permitted in Section 4928.143(B)(2)(h), Revised Code, under an infrastructure modernization plan, but that recovery of those investments not appear in any energy efficiency rider or energy efficiency cost category.

Revised Rule 39-07 must apply to both electric utilities with an ESP that authorizes single issue ratemaking for transmission and distribution infrastructure improvements under Section 4928.143(B)(2)(h), Revised Code, and to utilities whose rates have not been set pursuant to that provision. The Commission cannot by rule expand its statutory rate making authority. Thus, revised Rule 39-07(A)(1) clarifies that recovery for such infrastructure improvements as energy efficiency or demand reduction program costs should be limited to investments that are attributable to and undertaken primarily for energy efficiency or demand reduction purposes. Nothing in this rule prohibits utilities from seeking recovery for additional transmission and distribution improvements pursuant to Section 4928.143(B)(2)(h), Revised Code, or other applicable rate making statutes.

With respect to Rule 39-05(A)(2), now being adopted as Rule 39-07(A)(2), DP&L requests clarification that only a partial exemption should be allowed for integrated mercantile customer programs, with such exemption being in proportion to the amount of their load saved in relation to the then-current annual energy efficiency and demand reduction target. DP&L asserts that a mercantile customer should not be allowed to avoid the entire energy efficiency program charge assessed by the electric utility each year through the implementation of a program which produces only minimal savings.

The Commission believes that a partial exemption may be appropriate where mercantile customer energy savings and peak demand reductions, as a percentage of the customer's baseline period energy use and peak demand, are significantly below the utility's applicable energy efficiency and demand reduction requirements. We will review applications for exemption on a case-by-case basis.

FirstEnergy proposes new sections to this rule to expressly state that cost recovery approved under this rule is not by-passable except under the mercantile customer exemption under the following rule, and that such cost recovery may be allocated across all customers of the utilities within the same holding company system. As a general rule, the Commission will consider this to be non-by-passable, but reserves the right to review this issue on a case-by-case basis. Moreover, we find no statutory authority for allocation of energy efficiency and demand reduction costs across affiliated operating companies.

4901:1-39-06 Commitment for integration by mercantile customers

Before specifically addressing the comments on Rule 39-06, we note that this rule will be renumbered as Rule 39-08 in the attached rules.

DP&L contends that proposed Rule 39-06(A) should be modified to coordinate the benefits to a mercantile customer from participation in a PJM or MISO demand reduction program with those available through an electric utility's demand response program. DP&L asserts that a mercantile customer, or supplier to it, should be able to obtain the benefit of payments from PJM for participation in a PJM demand reduction program, or avoid paying a share of costs associated with the electric utility's demand reduction programs, but not both. DP&L also requests clarification on the verification of customer-provided impacts, and that an electric utility will not be penalized for any customer failure to meet program targets. In any event, DP&L asserts, any financial benefit to a customer should not exceed the product of the energy efficiency surcharge and the customer's baseline usage.

We have required that mercantile customers enter into special arrangements wherein all communications, protocols, and consequences for noncompliance are identified. In our March 18, 2009 opinion in Case No. 08-917-EL-SSO, the Commission recently indicated that we will consider customer participation in PJM demand reduction programs as a separate matter. Pending the outcome of that proceeding, we will consider participation in PJM demand reduction programs on a case-by-case basis an application proposes to incorporate participation in PJM programs into the electric utility's demand reduction programs.

With respect to proposed Rule 39-06, AEP contends that agreements with mercantile customers will be forward-looking in nature and relate to future energy reductions and demand reductions associated with customer-sited capabilities and resources. AEP criticizes the proposed rule for assuming a retrospective accounting can be performed, while in most instances, AEP expects that only projected events and results will be available. As described above, the new reporting requirements recognize the forward-looking nature of future energy efficiency and peak-demand reductions and provide for reconciliation when actual impacts have been measured and verified.

With respect to proposed Rule 39-06(D), FirstEnergy advocates the adoption of a new energy efficiency credit rule which would create energy efficiency credits that could be used for compliance with energy efficiency benchmarks at any time over the life of the initiative or project, similar to the renewable energy credits proposed in Chapter 4901:1-40. FirstEnergy asserts that such a rule would enhance the process of tracking and reporting compliance under SB 221 energy efficiency requirements by way of standard reporting tools such as the PJM Generator Attribute Tracking System, and would ensure that energy efficiency efforts that go beyond the statutory requirements are not unnecessarily stranded in that year.

While the Commission is open to the construct of energy efficiency credits, we are unaware of any accreditation regime currently operating in Ohio. The energy efficiency rules adopted herein do not prevent or preclude the use of energy efficiency credits and should such a regime be created, we may reconsider FirstEnergy's suggestion. In any event, the banking provisions in new Rule 39-05(E) should alleviate any concern about achieving more energy savings than required in any given year by allowing electric utilities to carry over savings in excess of the current benchmark to the future/following years.

Additionally, numerous clarifying language changes were suggested for proposed Rule 39-06, and many will be incorporated into the rule we adopt as Rule 39-08. We note, however, that some comments sought to extend the statutory provisions applicable to mercantile customers to residential or other customers, while others raise concerns that this Commission is attempting to expand our jurisdiction to include mercantile customers. The statutory provisions regarding commitment for integration are expressly limited to mercantile customers and, while our jurisdiction remains focused on electric utilities, those mercantile customers who wish to avail themselves of the benefits of integration will need to cooperate with the electric utility and this Commission as set forth in this rule, and will thereby become subject to certain compliance and verification proceedings.

OCEA argues that it will be impossible for the Commission to administer this regulation if any mercantile customer project completed in any prior year is eligible. The purpose of Section 4928.66, Revised Code, is that utilities implement programs that achieve significant energy savings and demand reductions beyond what would have occurred in the absence of such programs. Revised Rule 39-08(B)(4)(d) clarifies that the ordinary turnover of mercantile customer equipment to equipment that is standard within the industry is not subject to incorporation in utility programs. The revised Rule calculates mercantile customer savings and demand reductions based on the difference between the customer's capabilities and the energy use or peak demand produced by including standard new equipment and practices used to perform the same functions.

The Commission has clarified how mercantile customer energy savings and peak demand reductions will impact utility baselines. Revised Rule 39-08(B)(4)(d) better reflects the language and purpose of the statute. Under the revised Rule, a reduction in energy use or demand, which is a negative quantity, is excluded or subtracted from the utility's baseline. Subtracting a negative number mathematically increases the utility's baseline by the amount of the customer's reduction in energy use or demand. The revised Rule avoids double counting the mercantile customer's energy savings or demand reduction, once to the extent the customer's lower usage is already reflected in the utility's baseline and again if the reduction is incorporated into the utility's program. It avoids overstating the impact of mercantile customer reductions and diluting the energy efficiency and peak demand reduction standards

The first program portfolio filing is required by January 1, 2010. It must include the assessment of potential. This provides sufficient lead-time to develop the assessment of potential and to prioritize programs that may comprise the initial portfolio such that the least cost opportunities may be exploited first. We believe that updating the portfolio of programs every three years strikes a balance between adjustments such as allowing programs to mature and bear fruit before considering their natural conclusion and planning for new programs on the one hand, and timely responsiveness on the other hand.

The initial benchmark report is due within sixty days of the effective date of this rule. Given the process requirements, this should afford electric utilities enough time to calculate the baselines and benchmarks, and also provide staff and interested parties time to review these calculations prior to their use in any additional filings. Subsequent program portfolio status reports are required every April 15th for two reasons. First, it allows the electric utilities time enough to gather, analyze, and present data and information on the programs' impacts and whether they are sufficient for the electric utility to be in compliance with benchmarks. Second, the timing of April 15th coincides with the filing ofLTFRs, andIRPs. The LTFR and IRP both provide context for considering the impacts of energy efficiency and peak demand reduction programs. It is also required that baselines be set using forecast data and information. By filing them simultaneously, the transparency of setting the baselines is enhanced because all stakeholders can see the derivation and basis for calculating the baselines.

Chapter: 4901:1-40 Alternative Energy Portfolio Standard

LS Power suggests that the Commission should incorporate within Chapter 4901:1-40 a competitive procurement requirement under which electric utilities procuring alternative energy resources must employ a Commission-designed or approved request-for-proposal (RFP) process, designed to plainly show all market participants that the process is fair. LS Power suggests that, at a minimum, an electric utility should not be allowed to demonstrate that the cost cap under Section 4928.64(C)(3), Revised Code, has been exceeded, or that the electric utility is prevented by force majeure from complying with the renewable mandate under Section 4928.64(C)(4), Revised Code, without evidence of conditions throughout the entire renewable resource market and that such a showing cannot be made without the electric utility having employed an effective, Commission-designed RFP process.

The Commission would note that 40-06(A)(1) requires electric utilities or electric services companies seeking a force majeure determination to demonstrate that they have pursued all reasonable compliance options, including specifically REC solicitations. In addition, both 40-07(A)(2) and (B)(2) require that electric utilities or electric services companies pursue all reasonable compliance options prior to seeking relief under the cost cap provisions.

4901:1-40-01 Definitions

The Competitive Suppliers suggest that the definition for "biologically derived methane gas" be amended to add the phrase "including but not limited to municipally owned landfills" immediately after "landfill methane gas." The proposed revision creates a redundancy and is, therefore, not required.

In its comments, Vertus suggests a list of feedstock materials be included under the definition of "biomass energy" but also seeks to exclude agricultural and tree crops. OCEA and the Wind Advocates also support the exclusion of forest and agricultural crops from the definition, and urge that the exclusion extend to forest and agricultural crop residues or by-products derived from federal lands or land that was not cleared prior to enactment of SB 221. In reply comments, AMP-Ohio, DP&L, the Farm Bureau, and New Generation disagree with these proposed exclusions. Duke suggests that "biomass energy" should include clean demolition and construction material.

We note that Section 4928.01(A)(35), Revised Code, lists biomass energy as a type of renewable energy resource but does not specifically define the term. The Commission believes that it is important to include energy crops as potential sources in the definition of biomass energy. Excluding agricultural or tree crops from the definition of biomass energy, as Vertus suggests would preclude the use of cellulosic biomass feed stocks under research and development today, such as fast growing varieties of tree and agricultural crops under regular harvest for conversion to bioenergy. Biomass energy crops may include trees, shrubs, and grasses that have environmental and land-use benefits including use of marginal agricultural and reclaimed land, potentially lower energy and production inputs, and carbon sequestration.

With regard to wood biomass resources, the Commission believes the definition of biomass should include waste streams, such as wood and paper manufacturing waste, urban wood and tree residues, forestry residues from continuing forest management and harvest operations, or other land clearing. However, the Commission also conditions the use of forest resources upon sustainable forest management operations. Rule 40-04(E) introduces a certification process in which specific resources or technologies, including consideration of fuel or feedstock as applicable, will be evaluated. As indicated by 40-04(E)(2), such process would include the potential for interested persons to intervene and request a hearing.

The Competitive Suppliers suggest that the definition of "clean coal technology" be revised as follows:

> "Clean coal technology" means a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed in ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or

> sulfur trioxide in accordance with American society of testing and materials standard D1757A or a reduction in metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that include the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion.

OCEA requests that the Commission adopt the definition of a clean coal facility that is used in Illinois. OCEA notes that "clean coal technology" as defined in Section 4928.01(A)(34)(c), Revised Code, expressly authorizes the Commission to adopt specific design capabilities based on economically feasible best available technology or generally accepted scientific opinion. OCEA criticizes proposed Rule 40-01(F) for merely defining "clean coal technology" in the same manner as the statute, which could allow a proposed project to designate itself as a clean coal technology based upon a statement of its design capability without having removed a single pollutant from the air. To correct this deficiency, OCEA recommends that proposed Rule 40-01(F) should be revised to include specific design capability standards.

The Commission recognizes its statutory authority to adopt specific design capabilities for clean coal technologies under Section 4928.01(A)(34)(c), Revised Code. We believe, however, that the definitions and processes contained in 40-01(F), 40-04(E) and 41-03(C) provide adequate guidance to meet these statutory requirements..

Duke suggests that the term "co-firing" in proposed Rule 40-01(G) should be broadly construed to include the use of alternative fuels where a cost benefit analysis demonstrates long-term benefits for consumers. OCEA recommends that the proposed rule be revised to parallel the Commission's proposed qualification on the use of biomass energy as a qualifying renewable energy resource in proposed Rule 40-04(A)(6). The Wind Advocates suggests that the fuel source should dictate what portion of the output should qualify as advanced or renewable. We generally agree, as fuel inputs should be measured by estimated energy content rather than volume or some other measure. We are, therefore, adding additional language to this definition to clarify that the amount of electricity output from a co-firing facility that will qualify as a renewable energy resource will be determined by the proportion of energy input from a renewable energy resource.

Duke asserts that the definition of "deliverable into this state" should include facilities within the PJM and MISO transmission organizations so long as the electric utility or provider can demonstrate an available transmission path. FirstEnergy and the Competitive Suppliers urge that the PJM and MISO areas be included without qualification. DP&L argues that, since both PJM and MISO require a study to be performed prior to the interconnection of any generation source they operate, the Commission can assume that output from a new generation facility is deliverable throughout PJM or MISO subject only to emergencies or congestion pricing. DP&L also contends that the term be expanded to apply to both electricity and a renewable energy certificate (REC) as defined later in this rule. In addition, DP&L suggests that, for facilities outside Ohio, in contiguous states, and in PJM's or MISO's footprint, the demonstration should focus on a potential transmission contract path rather than a physical path since electricity flows along the path of least resistance, whereas purchase power contracts regularly assume a "contract path" that is counter to the physical flow of electrons. In any event, the demonstration should only require the possibility of a transmission contract path, not actual executed contracts. DP&L maintains that this expanded definition will promote the least-cost and most efficient options for purchasing renewable power, and is consistent with the reality of how RECs are bought, sold, and retired.

While some comments urge this Commission to expand the definition of "deliverable into this state" to include any generation originating within the PJM or MISO transmission systems, we believe a demonstration of delivery via a power flow study and/or deliverability study should be necessary, although not to the extent of requiring signed contracts. With that clarification, we do not find any need to revise proposed Rule 40-01(I).

Several comments were made regarding the definition of "distributed generation" in Rule 40-01(L). Some of these proposals focus on the location in the electric system and ownership of the generator, while others reference types of generation equipment. Taking into consideration these comments, the Commission has clarified the definition of "distributed generation," to reflect that it is generation located on-site whether owned by the customer or a third party. In addition, we believe it may be helpful to clarify our views on ownership of any RECs in distributed generation applications. It is the Commission's belief that RECs should belong to the owner of the equipment that produces the electricity underlying the RECs, unless there is contractual language that dictates otherwise. Therefore, in a net metering scenario, a resident owning and employing a qualified resource would retain any claim to the associated RECs unless ownership was otherwise established in a contract. Such RECs cannot automatically be claimed by the electric utility.

With regard to Rule 40-01(M), AEP, FirstEnergy and Duke object to the proposed definition of "double counting" as lacking statutory authority, and they suggest there is no rationale for prohibiting a single resource, such as a solar panel, from being used for both energy efficiency and renewable energy requirements. They maintain that energy savings should be able to be counted toward both the 25 percent alternative energy mandate as well as the 22 percent energy efficiency mandate. FirstEnergy argues that these statutory goals are not mutually exclusive, but that, if more requirements can be satisfied with less investment, such practice should be encouraged, not discouraged.

DP&L agrees that a prohibition should exist to prevent double counting of the same resource by two different entities, but seeks clarification that such a prohibition would not extend to the use of a resource to comply with multiple requirements imposed by two different governmental entities, such as similar state and federal requirements. DP&L also requests clarification regarding the references to product offerings and marketing claims, asserting that if an electric utility buys a REC and is compensated through a green energy tariff, the costs would not also be recoverable through a rider to recover SB 221 compliance costs.

With respect to staff's proposed definition of "double counting" of energy efficiency and demand-side management efforts towards the requirements of both Sections 4928.64 and 4928.66, Revised Code, the Commission does not believe that it is appropriate to recognize the specific benefits of these activities under both requirements simultaneously. Similarly, in a voluntary green pricing program under which an electric utility is fully compensated by its tariff rate, RECs which are acquired for such program should not also qualify toward compliance with the alternative energy portfolio standards in Section 4928.64, Revised Code. We have also clarified that it is not permissible to count renewable generation if the REC associated with that generation can be transferred and used for a different purpose. However, in the event that a national portfolio standard is enacted, it is not our intent to require an additional layer of compliance above any potential national renewable or advanced energy standard.

As proposed, "fully aggregated" would mean that "the renewable energy credit shall retain all of its attributes, including those pertaining to air emissions, and that specific attributes are not separated from the renewable energy credit and sold individually." DP&L suggests that the term "environmental" be inserted before "attributes" in both instances, to clarify that a REC may be purchased separately from the energy output, but that a single renewable megawatt-hour (MWH) cannot be separated into multiple compliance credits (such as SO_2 RECs, NOx RECs, carbon RECs, etc.).

FirstEnergy opposes the proposed definition. It argues that, to be consistent with other states, a REC should be a separate attribute from energy, capacity, and ancillary services, and any other current or future attribute associated with the MWH of renewable energy that resulted in the REC's creation.

The Competitive Suppliers suggest that a new definition for "green attributes" be added to describe the benefits of renewable generation. That proposed definition provides, in part, that "green attributes" mean any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the electric generation facility and its displacement of conventional energy generation/production. They propose that "fully aggregated" be modified to mean that the REC will retain all of its green attributes.

The definition we are adopting in this proceeding in Rule 40-01(T) clarifies that environmental attributes may not be unbundled from the REC and sold individually, although the credit may be unbundled from the electricity with which the REC was originally associated.

Staff defined "renewable energy credit" in Rule 40-01(DD) to mean the fully aggregated attributes associated with one-megawatt hour of electricity generated by a renewable energy resource. FirstEnergy proposes an alternative definition it believes to be clearer and more flexible: "'Renewable energy credit' represents one megawatt hour of renewable energy generation, whether self-generated, purchased along with the commodity, or separately through a tradable instrument."

Although SB 221 does not specifically address the unbundling of RECs, Section 4928.65, Revised Code, does indicate that RECs can be used for compliance. The Commission believes that the unbundling of RECs from the associated electricity is consistent with the legislation and should result in lower costs of compliance. Accordingly, we will add language to clarify the definitions of "fully aggregated" and "renewable energy credit" in this rule.

Duke suggests that the definition of "wind energy" should be revised to include energy storage such as compressors that store compressed air for daytime energy production or peaking purposes. As discussed in 40-04(A) below, the Commission acknowledges the potential benefits of energy storage systems, but we do not believe that energy storage, by itself, automatically constitutes a renewable energy resource, without qualification.

The Competitive Suppliers suggest that a new definition for "annual report" be added to denote the detailed information required to be filed by the electric utilities pursuant to Section 4905.14, Revised Code, and by electric service providers under Section 4928.06, Revised Code. While the rules adopted in this order provide for a number of new or expanded reports, we do not believe any reference to the annual reports filed pursuant to Section 4905.14, Revised Code, need be included in this chapter.

4901:1-40-03 Requirements

DP&L suggests amending proposed Rule 40-03(A) to clarify that it is not to be read as conflicting with the definition of "deliverable into this state" in Rule 40-01(I), above. DP&L also suggests that the phrase "including solar energy resources" in Rule 40-03(A)(2)(a) be deleted to clarify that SB 221 does not require half of all solar energy resources to be from Ohio facilities. Further, DP&L contends that Rule 40-03(A)(3) is in potential conflict with Section 4928.143(B)(2)(c), Revised Code, which provides for a non-by-passable charge for any type of generation resource that meets certain criteria and is found to be needed pursuant to an integrated resource plan. DP&L suggests modifying this paragraph to identify this statutory exception.

Duke suggests that this provision should be amended to specify that only energy costs incurred by the electric utility in complying with the alternative energy portfolio standard are avoidable by a choice customer. Duke asserts that an unavoidable capacity charge is necessary to meet the Ohio mandates, and that utilities will not invest in significant renewable capacity additions without an unavoidable capacity charge such as expressly provided under Sections 4928.143(B)(2)(b) and (c), Revised Code.

The rule we are adopting in this order will be modified to reflect some of the suggested changes to harmonize the definition of "deliverable into this state" in Rule 40-01(I) with this provision.

As with proposed Rule 39-04, the issue of whether a "rolling average" should be used to compute the three-year base period was also raised by the utilities for proposed Rule 40-03(B). The issue is whether the baseline period should be 2006 through 2008 (the three years prior to January 1, 2009), or a "rolling average" under which the three years used to calculate the base period would change each year. The utilities argue that the use of a rolling average would result in a compounding effect that would, over time, make the targets impossible to achieve. In the alternative, DP&L suggests that the Commission could use a rolling three-year period, but make adjustments to eliminate the compounding effect. In addition, DP&L asserts that electric utilities who are members of PJM should use the peak demand set by PJM for billing purposes in determining the appropriate baseline.

As noted above, the Commission believes that the most reasonable interpretation of SB 221 requires a "rolling average" to be used, although an electric utility is not precluded from requesting reasonable adjustments at the time it files its report.

FirstEnergy contends that the proposed Rule 40-03(B) unfairly spreads the responsibility for compliance to companies that have been operating in the state where significant shopping has occurred. It further contends that Rule 40-03(B) fails to address the situation where suppliers default or move out of state. FirstEnergy suggests several changes to Rule 40-03(B). The Commission finds FirstEnergy's proposed changes would add a level of complexity that it has not shown to be necessary or required by the statute..

Several comments object to the provision that excused new competitive providers from complying with the portfolio standard requirements in their first year of service because new providers would not have any sales history during the applicable baseline period. The Competitive Suppliers argue that this provision would greatly disadvantage those suppliers currently operating in Ohio, and suggest that their prior sales be "grandfathered" by only counting sales on a prospective basis, to effectively level the playing field with new entrants.

The Commission recognizes that this proposed provision may represent an unfair advantage for a new provider. Therefore, we have revised the rule to require a new competitive provider to project sales for their first year. The projection will be used as the baseline calculation during its initial year of operation in the state.

With regard to proposed Rule 40-03(C), Duke contends that the 15-year planning horizon is not practical and should be reduced to five years. FirstEnergy asserts that there is no statutory basis for this provision beyond an annual filing for review of compliance with the most recent applicable benchmark under Section 4928.64, Revised Code. Duke suggests that the plan should also be incorporated into an existing forecast or resource plan process to avoid duplication of reporting requirements. FirstEnergy argues that such a long-term filing poses a significant burden for little apparent value, and contends that information regarding an electric services company's supply portfolio is confidential and should not be made public.

The Competitive Suppliers also complain that the proposed 15-year plan is not a practical requirement for electric services companies, since they typically enter into short-term contracts and are unable to predict with any meaningful degree of certainty what their customer load will be beyond the following year. They suggest a one-year planning period would better reflect the business model for these providers.

The Competitive Suppliers also suggest that new subsections D through F be added to Rule 40-03 to detail a one-year planning and annual compliance report filing for electric services companies that would be afforded confidential treatment for a three-year period without any requirements of motion or entry under Rule 4901-1-24, O.A.C.

Numerous comments on paragraph (C) of proposed Rule 40-03 have led us to clarify that the plan will be formally docketed and to adopt a shorter ten-year planning horizon. These changes are more consistent with the proposed IRP requirements, with an expectation that efforts under both sections will be closely coordinated. The Commission also acknowledges, in response to several comments, that the contents of the plan are nonbinding. Compliance with the alternative energy portfolio standard requirements is expected to be dynamic, and therefore a forward-looking compliance plan is expected to be revisited and updated as new information becomes available. The plan contents were also revised to gather more targeted information to be used, in part, for the development of the annual reports that the Commission is required to provide to the General Assembly under Section 4928.64(D)(1), Revised Code.

4901:1-40-04 Qualified resources.

Proposed Rule 40-04(A) identifies qualified resources for meeting renewable energy resource benchmarks. Duke contends that the term "biomass energy" and its measurements should always include biologically derived methane gas, with or without co-firing, to be consistent with Section 4928.01(A)(35), Revised Code.

FirstEnergy asserts that this provision contains limitations in conflict with express language of the statute under Section 4928.01(A)(35), Revised Code, which defines a "renewable energy resource" to include a "storage facility that will promote the better utilization of a renewable energy resource that primarily generates off peak." FirstEnergy argues that wind is clearly a renewable resource that primarily generates off peak, and since a storage facility has the unique capability to move generation in time from off-peak to on-peak, such storage clearly provides for better and more effective renewable energy utilization. FirstEnergy contends that such a storage facility will promote the better utilization of a renewable energy resource that primarily generates off peak by allowing control of a facility which would otherwise be an undependable source, by enhancing the value to customers and the resource owner in delivery power to the marketplace at optimal times, and thereby encouraging further investment in and development of wind resources.

Although the Commission acknowledges the potential benefits of energy storage systems, we do not believe that energy storage, by itself, automatically constitutes a renewable energy resource without qualification. The Commission also deems it appropriate to modify Rule 40-04(A) to clarify that solid waste energy must go beyond trash-burning and to eliminate limitations on biomass energy and fuel cells as qualifying resources.

OECA recommends a modification to Rule 40-04(B)(1) to clarify that any modification to an electric generation facility will qualify only if the facilities total annual carbon dioxide emissions do not increase. We agree that Section 4928.01(A)(34)(a), Revised Code, permits generator modifications to qualify only if the increase in output is achieved without additional carbon dioxide emissions. We have revised the rule to ensure that this requirement is met.

Several comments seek clarification to determine if the Commission intends to recognize incremental or total generation from certain facilities under Rule 40-04(B). We find this concept adds value in some instances, and we have added language to indicate when an incremental benefit would be recognized.

Proposed Rule 40-04(C) lists the mercantile customer-sited resources that may be qualified resources for meeting electric utilities' annual renewable energy resource benchmarks or advanced energy resource benchmarks. The Competitive Suppliers contend that this provision should be expanded to allow new or existing mercantile customer-sited resources to count toward meeting renewable and advanced energy benchmarks for electric service providers, as well as electric distribution utilities. They argue that the staff- proposed rule would put them at a competitive and financial disadvantage, and that there is no reason to preclude electric service providers from counting these resources toward their benchmarks. We find that the Competitive Suppliers' suggestion is not supported by the statute. Section 4928.64(A)(1), Revised Code, limits the ability of mercantile customers to commit advanced energy resources or renewable energy resources "into the ***electric distribution utility's*** demand-response, energy efficiency, or peak demand reduction programs...". [emphasis added]

The Competitive Suppliers also assert that biologically derived methane gas should be included as a qualified resource under Rule 40-04(C). We note that biologically derived methane gas is expressly listed as a qualified renewable resource, under Section 4928.01(A)(35), Revised Code, and is, therefore, a qualified renewable resource under Rule 40-01(EE). Further, the definition of "biomass energy" in 40-01(E) includes language pertaining to biologically-derived methane gas.

Several electric utilities object to the prohibition against double-counting in the proposed rule as being without statutory basis or reasonable basis. They contend that a single resource, such as a solar panel, should count toward both the 22 percent energy savings mandate by the year 2025 under Section 4928.66, Revised Code, and the 25 percent alternative energy resource mandate by the year 2025 under Section 4928.64(A)(1), Revised Code. They note that Section 4928.64, Revised Code, expressly states that advanced energy resources include energy efficiency, while the statutory definition of "advance energy resource" under Section 4928.01(34)(g), Revised Code, specifically includes DSM and energy efficiency resources. Therefore, they argue, Staff's proposed rule must be revised to permit energy efficiency program results to be counted toward both the alternative energy benchmarks as well as the energy efficiency benchmarks.

As noted in our discussion of Rule 40-01(M) above, the Commission believes this rule appropriately prohibits the double-counting of single resource toward compliance with the requirements of both Sections 4928.64 and 4928.66, Revised Code. However, in the event that a national portfolio standard is enacted, it is not our intent to require an additional layer of compliance above any potential national renewable or advanced energy standard.

Proposed Rule 40-04(D) provides that an electric utility or electric services company may also use RECs to satisfy all or part of a renewable energy resource benchmark. Duke suggests that the proposed rule would allow an electric utility to acquire RECs from other parts of the country, but requests clarification whether the use of such RECs be conditioned upon a demonstration that the energy from the generation source creating the purchased RECs is capable of being delivered into the state of Ohio. We believe the most appropriate interpretation consistent with SB 221 is to require that the use of RECs be limited to those associated with electricity originating in Ohio, or deliverable into this state, as defined in Rule 01(I).

Multiple comments addressed the life of a REC (i.e., the length of time that a REC can be banked), with several different interpretations of the language in Section 4928.65, Revised Code, being offered. The Commission believes that Rule 40-04(D)(3) is consistent with the foregoing statutory provision. RECs retained by the original generator have an unlimited life, while purchased or acquired RECs will have a life of five years from the date of initial purchase or acquisition.

We are also adding clarification that only RECs generated after the effective date of SB 221 will be permitted for use towards compliance. The Commission does not believe it is reasonable to utilize RECs generated prior to July 31, 2008, for compliance purposes, and has added language to this effect in Rule 40-04(D)(6).

4901:1-40-05 Annual compliance reviews

We have substantially changed the review procedures in this rule to more closely reflect the annual review of compliance process adopted in Chapter 39.

4901:1-40-06 Force majeure

We again note LS Power's suggestion to incorporate a competitive procurement requirement which would require an electric utility to demonstrate that it had employed an effective, approved, and transparent RFP process as a condition precedent for any determination that a cost cap was exceeded under Section 4928.64(C)(3), Revised Code, or that the electric utility is entitled to force majeure relief under Section 4928.64(C)(4), Revised Code. As mentioned previously, 40-06(A)(1) requires electric utilities or electric services companies seeking a force majeure determination to demonstrate that they have pursued all reasonable compliance options, including specifically REC solicitations. In addition, both 40-07(A)(2) and (B)(2) require that electric utilities or electric services companies pursue all reasonable compliance options prior to seeking relief under the cost cap provisions.

No substantive changes were deemed necessary to this rule, and it will be adopted as proposed.

4901:1-40-07 Cost cap

The electric utilities contend that proposed Rule 40-07 fails to conform to the statutory language of Section 4928.64(C)(3), Revised Code, which provides:

> An electric distribution utility or an electric services company need not comply with a benchmark under division (B)(1) or (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise

producing or acquiring the requisite electricity by three per cent or more.

The electric utilities argue that proposed Rules 40-07(A) and (B) set up two separate caps for advanced and renewable benchmarks, respectively, rather than providing a single cap. They contend this effectively raises the statutory cap from three to six percent.

The Commission believes that the proposed rule regarding benchmarks is the most reasonable interpretation of Section 4928.64, Revised Code, consistent with the goals of SB 221. We note that the statutory language quoted above expressly provides that compliance is waived under "division (B)(1) or (2)" which indicates that there are two separate caps which must be applied.

FirstEnergy also objects to the proposed rule's use of the electric utility's "reasonably expected generation rate" rather than the statutory language of "reasonably expected cost of otherwise producing or acquiring the requisite electricity" to determine the cap.

The Competitive Suppliers contend that it would be difficult for an electric services company to comply with this provision as proposed by staff. They note that other states use publicly available information to determine whether an electric services company has exceeded the cost cap for renewable energy, and that New Jersey has proposed to use data collected by the EIA of the U.S. Department of Energy under Form EIA-826, which provides a 12-month average retail price of electricity to ultimate customers in all sectors and is specified by state. The Competitive Suppliers suggest that the EIA-826 data would be an appropriate basis for determining whether competitive suppliers have reached a cost cap in meeting the benchmarks since the prices paid by customers of CRES providers vary on a customer-by-customer basis. They also assert that costs incurred by an electric services company in meeting its benchmark obligation is highly sensitive competitive information which should be protected from public disclosure for a three-year period in order to prevent competitive harm. The issues raised by the Competitive Suppliers will initially be addressed on a case-by-case should any Competitive Suppliers request a determination from the Commission regarding its cost of compliance. Rule 40-07(A)(1) and (B)(1) indicate that an electric utility or electric services company maintains the burden of proof for substantiating a claim under the cost cap provision of the rule.

Duke argues that proposed Rule 40-07(C) should include capacity as part of the renewable compliance costs, and suggests that the cost for renewable energy (and capacity if applicable) be compared to the wholesale market cost of traditional energy (and capacity if applicable) based upon an average price of the portfolio held by the electric utility or electric service company. Duke asserts that the price of renewable energy may fare better in such comparison than the price of renewable capacity, which is significantly more than three percent in excess of the price of traditional capacity, and that distinct treatment of energy and capacity will encourage additional investment in renewable resources.

We note that the cost of compliance with benchmarks under this section will reflect the market value of a REC. The market value of a REC reflects the unbundled environmental attributes of a renewable resource, not the value of energy and capacity. We therefore reject Duke's suggestion.

FirstEnergy states that proposed Rule 40-07(C) is inconsistent with SB 221 since it implies that the three percent cost cap is calculated by comparing the electric utility's total generation rate with alternative energy resource expenditures, to the total generation rate without alternative energy resource expenditures. FirstEnergy contends that 40-07(C) conflicts with the clear statutory language of Section 4928.64(C)(3), Revised Code, which uses the phrase "cost of otherwise producing or acquiring the *requisite* electricity" (emphasis added). FirstEnergy argues that the use of the phrase clearly indicates that the three percent cost should measure the difference in costs on the specific generation required to meet the benchmark, not between the total generation with and without alternative energy resources.

OCEA contends that FirstEnergy's position lacks a statutory basis and appears to trigger the cost cap prematurely so that utilities need not invest in alternative energy technologies. OCEA argues that the cost cap is to protect ratepayers from significant increases in their electric bills and the fairest way to do that is to assess the cost to ratepayers overall rather than isolating "specific generation" associated with meeting a benchmark.

The Commission agrees that the function of the cost cap is to protect consumers from significant increases in their electric bills. It should be calculated based on a comparison of generation costs to meet the total consumer electricity requirements. Given that different types of generation will be dispatched differently and have different impacts on electricity prices, any attempt to base the cap on a comparison of the "difference in costs" of specific types of generation would be inherently arbitrary.

After reviewing the comments of the parties, we find that the most appropriate interpretation of the statute provides for two separate three percent cost caps, one for renewable energy resources and one for advanced energy resources. As the first benchmark for advanced energy does not appear until the end of 2024, there would only be the cap for renewable energy resources, including solar, for the immediate future. In addition, the word "may" in this paragraph and Rule 07(D) will be changed to "shall" to eliminate uncertainty as to how the cost caps would be implemented.

Proposed Rule 40-07(D) provides that any costs included in an unavoidable surcharge for construction or environmental expenditures of generation resources may be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard. OCEA and AWEA both read the proposed rule as suggesting that certain environmental costs covered by Section 4928.143, Revised Code, would be excluded from the calculation of the expected generation rate exclusive of any reasonable compliance costs associated with the portfolio standard requirements. They argue that such an approach, when applying the percentage cap, would reduce the dollar increment available for compliance activities. We are adding language to clarify our intent that costs for which a non-by-passable surcharge have been approved should be included in the calculation of the expected generation rate. However, these costs would not be considered a cost of compliance with Section 4928.64, Revised Code, and would not, therefore, exhaust any portion of a three percent cap.

Proposed Rule 40-07(E) provides that compliance with each benchmark shall be achieved up to the point that the three percent increment would be reached. FirstEnergy objects to the use of the phrase "up to the point" in the proposed rule, as being in conflict with the statutory language in Section 4928.64(C)(3), Revised Code, which states that the electric utility "need not comply" with the benchmarks if the cap is reached. FirstEnergy asserts that there is no legislative contemplation of an "up to" standard for the cost cap and the Commission has no power to modify the application of the statute. As OCEA points out, FirstEnergy failed to consider all of Section 4928.64(C)(3), Revised Code. The statute provides that compliance is not required "to the extent" that costs exceed the three percent cap.

FirstEnergy claims that proposed Rule 40-07(F), which would require compliance in a future year by an amount of any undercompliance in a previous year due to the three percent cost cap, exceeds the Commission's statutory authority and should be deleted. DP&L contends that it is error to conclude that there is undercompliance in such circumstance because the electric utility fully complied with the statutory requirement. AEP also recommended deleting the proposed paragraph because it has the effect of overriding the cap protection specifically adopted by the General Assembly. The Commission believes that the proposed provision is not required to be included in this rule, but we are reserving the right to impose such a "catch-up" requirement on a case-by-case basis. .

4901:1-40-08 Compliance payments

Duke contends that the escalation provision to be applied to forfeitures for noncompliance with renewable energy benchmarks under the proposed Rule 40-08(A)(2)(b) is not expressly provided in SB 221, and should be deleted. FirstEnergy suggests that if the Commission were to increase compliance payments under proposed Rule 08(3)(a), due process requires that the electric utility or electric services company should be given sufficient notice before such action is taken.

Contrary to Duke's assertion, the Commission's authority to increase the amount of a compliance payment is specified in Section 4928.64(C)(2)(b), Revised Code. We do, however, note that this Commission intends that reasonable notice would be given in the event that such an increase becomes appropriate.

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

In addition to the modifications discussed below, a new Rule 40-02 will be added to specify the chapter's purpose and scope, consistent with the Commission's rulemaking practice, as discussed above.

4901:1-41-01 Definitions

In it comments, Duke suggests that the official title for "The Climate Registry" in Rule 41-01(C) be used in this chapter, but notes that the USEPA may establish its own mandatory reporting program, and recommends that the proposed rule be modified to accommodate reporting changes, if appropriate.

While we acknowledge Duke's concern, we believe Ohio should move forward with this initiative and will revisit this issue at such time as a national reporting program becomes viable.

In response to comments from various stakeholders including the electric utilities, municipalities, consumer and environmental advocates, and private sector interests, we have modified staff's proposed definition of "electric generating facility" in Rule 41-01(D) to exclude plants of less than 50 MW in capacity.

4901:1-41-02 Greenhouse gas reporting and carbon dioxide control planning

As noted above, this rule is being renumbered as Rule 41-03 due to the addition of a new purpose and scope rule consistent with the other chapters.

FirstEnergy asserts that the proposed rule exceeds the Commission's jurisdiction and statutory authority, and is inconsistent with Section 4928.68, Revised Code, which provides:

> To the extent permitted by federal law, the public utilities commission shall adopt rules establishing greenhouse gas emission reporting requirements, including participation in the climate registry, and carbon dioxide control planning requirements for each electric generating facility that is located in this state, *is owned or operated by a public utility that is subject to the commission's jurisdiction*, and emits

> greenhouse gases, including facilities in operation on the effective date of this section. (emphasis added).

FirstEnergy argues that since its operating companies no longer own any generating facilities, the reporting requirements under the proposed rules would fall to FirstEnergy's unregulated affiliate, which now owns the plants. FirstEnergy contends that, since these facilities are no longer owned or operated by a public utility that is subject to the commission's jurisdiction, the reporting requirements would not apply.

FirstEnergy also suggests that The Climate Registry's general reporting protocol requires further public participation and workshops prior to requiring membership, to help stakeholders better understand reporting requirements and provide a more useful end product. FirstEnergy notes that, if the intent is to obtain greenhouse gas inventories, such data is currently available from the USEPA and the proposed reporting would be redundant and potentially inconsistent. In fact, FirstEnergy asserts, the Ohio EPA does not plan to require reporting to The Climate Registry.

DP&L suggests that further investigation is needed regarding fees and costs associated with The Climate Registry tracking and reporting requirements, and requests that staff convene a series of technical workshops or other proceedings to develop appropriate parameters for carbon dioxide control planning. In particular, DP&L suggests that a reasonably comprehensive study for controlling CO_2 emissions at existing power plants could be jointly funded by the electric utilities and provide the basis for development of additional requirements.

As noted above, the Commission acknowledges the various concerns raised in the comments, but we believe we must begin to address carbon dioxide control planning under SB 221. While there may be issues associated with The Climate Registry tracking and reporting requirements, we believe that compliance with this chapter will not prove to be unduly burdensome. However, the parties should now have had sufficient time to explore the implications of membership in The Climate Registry, and can raise any problems on rehearing. Furthermore, we may revisit this issue if a national reporting program becomes a viable option or mandatory requirement.

DP&L contends that the use of the term "environmental control plan" in proposed Rule 41-02(B) (which is new Rule 41-03(B)) is overbroad since the statutory basis is a single sentence in SB 221 calling for greenhouse gas reporting and carbon dioxide control planning requirements. We disagree with DP&L and believe that our adopted Rule 41-03(B) is consistent with the statute. Accordingly, the Commission rejects DP&L's proposed modification.

With respect to controlling emissions of carbon dioxide within the parameters of economically feasible best technology included in proposed Rule 41-02(C) (which is now

Rule 41-03(C)), FirstEnergy contends that there are no cost effective, commercially demonstrated or available control technologies. DP&L also objects to proposed Rule 41-02(C) as being an excessively broad and ill-defined mandate, which would require truckloads of emissions data, engineering schematics, and studies. DP&L also contends that the use of the phrase "economically feasible best technology" would require cost estimates for each technology. DP&L urges the Commission not to implement proposed Rules 41-02(B) or (C) at this time, but to instead convene technical conferences to better define the information to be developed and filed.

Comments on this new chapter from the electric utilities and municipalities questioned the rules' intent to include facilities, which they deem to be outside the scope of the law. Questions were raised by several parties about the definition and inclusion of the term "person" as too broad in its application as well as the designated recipient of the information sought by the rule. The consumer and environmental advocates requested inclusion of alternative technologies and harmony with other commission rules.

After review, the Commission finds that, in general, in yielding a rule that is in the best interest of Ohio and its citizens, it cannot accept the arguments raised. As the advocates correctly point out, if only those under the Commission's traditional direct jurisdiction are subject to greenhouse gas reporting requirements, such a narrow interpretation would exempt so many entities from the monitoring and reporting requirements as to essentially render the rule meaningless. In addition, a broader interpretation is consistent with, and necessary for, the Commission's oversight of IRP planning and the advanced energy portfolio standards, as mandated in SB 221.

We do recognize, however, the validity of the stakeholder arguments for a jurisdictional threshold on the size for reporting facilities. Therefore, an exemption for generating facilities of less than 50 MW in capacity was added to the adopted rule to reflect the corresponding megawatt level used in the Ohio Power Siting statute. In addition, the reference to "scope 1 (direct) greenhouse gas emissions" was removed at the suggestion of The Climate Registry.

LONG-TERM FORECAST CHAPTERS

As noted previously, the Commission's forecast rules are being modified to restore the IRP requirements under Chapter 4901:5-5 in response to SB 221, and to restore the general gas and electric forecasting chapters so as to not impact, through this proceeding, the gas and natural gas companies, except for the correction of two O.A.C. references contained in existing Rules 4901:5-1-01(G) and 4901:5-3-01(B), O.A.C. Therefore, our modifications focus on those required by SB 221.

<u>**Chapter 4901:5-1 Long-Term Forecast Reports**</u>

<u>**4901:5-1-01 Definitions.**</u>

Changes to staff's proposed modifications to Rule 4901:5-1-01[6] consist of corrections to rule and statutory references, and the elimination the phrase in the second section of the "substantial change" definition. Much of the discussion from the comments focused on this definition because a "substantial change" triggered an electric utility's obligation to file a resource plan with its LTFR. As discussed below, we are now convinced that each electric utility should include a resource plan with its annual LTFR in order for this Commission to make informed decisions dependent upon the status of Ohio's energy industries and markets.

While the ESP or the market-based option are the two methods established by SB 221 for the Commission to set generation rates, the LTFR will be the tool used by the Commission to assess the reasonableness of the demand and supply forecasts based on anticipated population and economic growth in the state in accordance with Section 4935.04(F)(5), Revised Code. The forecast review process and the rate setting process are two independent regulatory functions of the Commission. The former assesses the need for the state of Ohio pursuant to Sections 4935.04(E)(2)(a) and (b), Revised Code, and the latter determines the rates pursuant to Section 4928.142 or 4928.143, Revised Code.

Section 4935.04(C)(1), Revised Code, requires the LTFR to contain 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. This statute does not distinguish between electric utilities that have their rates set pursuant to Section 4928.142, Revised Code, and those that have their rates set pursuant to Section 4928.143, Revised Code. As long as the electric utility that is filing an LTFR owns a major electric utility facility or furnishes electricity directly to more than 15,000 customers in Ohio, it shall be required to include a resource plan in its annual LTFR.

IEU-Ohio suggests that the definition for a "person" under proposed Rule 1-01(G) and the purpose and scope section under proposed Rule 1-02(B) be modified to explicitly state that the LTFR reporting rules should not apply to customer-generators. We believe such a change is unnecessary in proposed Rule 1-01(G), which is now Rule 1-01(J). There is no requirement to file an LTFR so long as a customer-generator does not own a high voltage line or furnish electricity to more than 15,000 customers. We note, however, that the customer-generator will be subject to Power Siting Board jurisdiction if the customer's generating unit exceeds 50 MW. Additionally, the issue raised regarding Rule 1-02(B) is

[6] Similar to Chapters 4901:1-39, 4901:1-40, and 4901:1-41, the Commission will refer to the specific rules contained in Chapters 4901:5-1, 4901:5-3, 4901:5-5, and 4901:5-7 by their last three numbers instead of the full code section being discussed in each subsection of the order (see supra n.1).

moot with the elimination of the entire proposed new rule, which will be replaced with existing Rule 1-02.

<u>4901:5-1-03 Long-term forecast report-requirements</u>

OCEA recommends that a resource plan be included with all annual forecast reports, and we will adopt this suggestion. Although the proposed rules did not have an annual requirement, we believe that it is essential that each electric utility file an IRP with its annual forecast report in order for this Commission to develop an accurate view of Ohio's energy industries and markets, particularly in light of the efficiency and alternative energy requirements imposed by SB 221. The burden on Ohio utilities of filing annual resource plans, must be balanced against the need for timely review and adjustment to changes in how Ohioans produce and use, or do not use, energy. If the ultimate goals of SB 221 are achieved, an electric utility's application for new generation will no longer represent the only substantial change in resources which should trigger an evaluation of changed conditions.

We also note the concern raised by COSE that the duty to file a LTFR not be imposed on electricity aggregators. Since the aggregation groups do not directly supply power to their members, but only purchase power on behalf of customers, aggregators have not been required to file forecast reports in the past and no change in the application of this rule has been suggested or mandated by modifications to the rules in this proceeding.

Furthermore, as described previously, with the restoration of existing Rule 1-02, we have removed Rules 1-03(A) through (C) as they are now redundant.

<u>Chapter 4901:5-3 Filing and Fees for Long-Term Forecast Reports</u>

As discussed above, new Rules 3-01 and 3-02, which were proposed as additions to the existing chapter are being eliminated in order to restore existing Chapter 4901:5-3 with regard to provisions that affect gas and natural gas companies.

<u>Chapter 4901:5-5 Electric Utility Forecast Reports</u>

As noted above, Chapter 4901:5-5 is being modified to restore the former rules regarding IRPs and filing requirements, in response to SB 221, which is now Rule 5-06. The chapter is also being modified to incorporate a new second rule containing a statement of purpose and scope.

<u>4901:5-5-01 Definitions</u>

OCEA suggests that the definition of "demand-side management" in proposed Rule 5-01(F) should refer to programs delivered by or sponsored by the electric utility and paid for through customer rates. They contend that the proposed definition could be read to include the impact of customer-initiated programs, the impact of which may be discussed and evaluated by the electric utility, but which have a different purpose or impact compared to those over which the electric utility has control. We do not believe this distinction is necessary and will declined to adopt this modification at this time.

FirstEnergy suggests deleting the second sentence of the definition of "energy-price relationships" in proposed Rule 5-01(H) because the electric utilities may not know what causes a customer to switch to a CRES provider, and customers could move load from on-peak to off-peak without switching to a CRES. We agree and have made this change in the rule adopted by this order.

Numerous changes to staff's proposed modifications for this rule were suggested in the comments, and many are included for adoption in this rule. The term "system capability" will be relabeled as "available system capability," while the definitions for "demand" and "person" will be deleted as unnecessary for the purpose of this chapter. Other changes were made to clarify the terms "energy-price relationships," "load," and "TTC (Total Transfer Capacity)," to create a stand-alone definition for "load shape," and to add a definition for "price responsive demand."

4901:5-5-02 Forecast Report Requirements for Electric Utilities And Transmission Owners

As noted above, the current Rule 5-02 will be renumbered as Rule 5-03 to accommodate the addition of a new purpose and scope rule. After review of the comments submitted in this proceeding, we find that no substantive changes proposed are desired or necessary. Despite electric utility comments that staff proposed Rule 5-02(C)(2)(b) is burdensome and unnecessary in requiring a discussion of the impacts of new legislation or regulations, this Commission believes the required discussion is important to the accuracy of the forecast reports, to identify changes that may affect the forecast going forward. In addition, to the extent that energy policy deliberations are ongoing, information from the reporting person regarding potential impacts may aid the Commission, and other parties, in those deliberations.

Moreover, the Commission has added a provision to new Rule 5-03(C)(4) that, to the extent possible, requires the long-term forecast report to specify a demand function that captures the impact of price responsive demand. The Commission believes that this provision will be essential to assessing resource requirements as advanced metering and time-differentiated pricing are implemented under SB 221.

4901:5-5-03 Forecasts for electric transmission owners

As noted above, the current Rule 5-03 will be renumbered as Rule 5-04. Changes to the rule, as proposed by staff, were identified in paragraph (B)(4) to reflect that transmission owners should provide an analysis, either developed by them or for them, of the capability of their system to receive and deliver power, despite the electric utilities' assertions that the transmission information requested is not maintained by the companies. However, this information directly relates to the electric utilities' operations and can easily be retrieved from their respective RTOs. This provision can also apply directly to RTOs, which are doing business in Ohio, and thus, are subject to reporting requirements for Ohio-based assets. The same is true of holding company subsidiaries which "own" transmission facilities.

With respect to the issue of confidential information raised by AEP, we believe the use of redacted public copies and/or protective orders under existing Rule 4901-1-24, O.A.C., should prove sufficient to resolve the disclosure concerns of the electric utilities, customers, and parties.

4901:5-5-04 Energy and Demand Forecasts for Electric Utilities.

As noted above, the current Rule 04, will be renumbered as Rule 05. OCEA suggests that the proposed rule incorrectly assumes a single energy and demand forecast. OCEA contends that the report and resource plan should identify a range of demand forecasts and the assumptions for econometric and end-use variables that would be considered in the range of outcomes that complement the long-term forecasts of demand and consumption during the term of the plan. AEP and FirstEnergy object to this proposal as burdensome and not required for compliance with SB 221 mandates. AEP objects to OCEA's proposal to specify geographically-targeted DSM and distributed generation factors to the exclusion of other factors. We agree with AEP and will not adopt OCEA's suggestion for this rule; however, we reject AEP and FirstEnergy's argument that the rule is burdensome and unnecessary.

4901:5-5-05 Resource plans for electric distribution utilities.

As noted above, staff-proposed Rule 5-05, which will be renumbered as Rule 5-06, essentially restores the old IRP rule as the necessary planning and evaluation tool to implement the new energy efficiency, peak demand response, and alternative energy requirements mandated by SB 221. Much of the discussion in the comments regarding staff's proposed rule centered on OCEA's suggestion to require that each electric utility include a resource plan as part of its annual forecast report. We find it unnecessary to address these arguments given the extensive rewrite and new planning provisions being adopted in Chapter 4901:1-39, and our decision to require an annual IRP filing irrespective of whether the electric utility intends to seek recovery for a new or existing generation facility in an ESP.

As stated previously, we will adopt OCEA's suggestion to require an annual IRP filing as a necessary tool for this Commission to assess the reasonableness of the demand and supply forecasts based on anticipated population and economic growth in the state in accordance with Section 4935.04(F)(5), Revised Code. Section 4935.04(C)(1), Revised Code, requires the LTFR to contain 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, but does not distinguish between an electric utility whose rates are set under the market-based option of Section 4928.142, Revised Code, versus an electric utility whose rates are set in an ESP pursuant to Section 4928.143, Revised Code. So long as the electric utility that is filing an LTFR owns a major electric utility facility or furnishes electricity directly to more than 15,000 customers in Ohio, it shall be required to include a resource plan in its annual LTFR.

Numerous minor changes to staff's proposed rule were suggested in the comments, and many are reflected in our adoption of new Rule 5-06. As previously noted, we are mindful of the timing and coordination of the various filing requirements and proceedings imposed by Chapter 4901:1-39 and the forecast rules, and advise the electric utilities and stakeholders to work with staff in the development of practical and realistic timelines in accomplishing the goals of SB 221. Where practical and appropriate, electric utilities should seek to base their forecast filings under this chapter and their planning filings under Chapter 4901:1-39 on comparable data and assumptions.

Given the timing of the current rules process, the Commission will not require that the April 15, 2009 forecast filing include an integrated resource plan. The first integrated resource plan will be filed with the April 15, 2010 forecast reports. In the event, however, that an EDU should file for an allowance under the provisions of Section 4928.143, Revised Code, before April 15, 2010, the EDU will be required to file an amended 2009 forecast report which will include an integrated resource plan, in advance of their ESP filing.

CONCLUSION:

After reviewing staff's proposal and the comments filed in this proceeding, the Commission will adopt new Chapters 4901:1-39, 4901:1-40, and 4901:1-41 as attached to this order. Further, the Commission will rescind the existing electric forecast rules contained in Chapter 4901:5-5, O.A.C., and adopt the new chapters attached to this order. The rules to be adopted by this Commission and filed for review by JCARR, showing only the new or current rule as modified herein, are attached to this order for filing in this docket but, as in prior rules proceedings, will not be included in the hard-copy distribution of this order. Instead, access to the rules is available on the Commission's website at www.puco.ohio.gov/puco/rules/ by clicking on the link titled

"Implementation of S.B. 221 - Green Rules: Proposed Rules for Energy Efficiency & Alternative Energy Portfolio Standard, and Modifications to Forecast Rules" or by searching for this opinion and order in the Commission's Docketing Information System under Case No. 08-888. Members of the public without internet access may request a paper copy by contacting the Commission's Docketing Division at (614) 466-4095.

ORDER:

It is, therefore,

ORDERED, That the attached rules are hereby adopted. It is, further,

ORDERED, That existing Chapter 4901:5-5, O.A.C., be rescinded. It is, further,

ORDERED, That attached new Chapters 4901:1-39, 4901:1-40, 4901:1-41, 4901:5-1, 4901:5-3, and 4901:5-5, O.A.C., be filed with the Joint Committee on Agency Rule Review, the Secretary of State, and the Legislative Service Commission in accordance with divisions (D) and (E) of Section 111.15, Revised Code. It is, further,

ORDERED, That the final rules be effective on the earliest day permitted by law. Unless otherwise ordered by the Commission, the review date for Chapters 4901:1-39, 4901:1-40, and 4901:1-41 shall be May 31, 2014. It is, further,

ORDERED, That a copy of this entry, without the attachments, be served upon all parties filing comments in this docket, all electric, gas, and natural gas companies, electric transmission owners, and all interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

RMB:geb

Entered in the Journal

APR 15 2009

Reneé J. Jenkins
Secretary

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4901:1-39-01 **Definitions.**

(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) "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.

(D) "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.

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

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

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

(H) "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.

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

(J) "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.

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

(L) "Independent program evaluator" means the person or firm hired by the electric utility at the direction of the commission staff to measure and verify the energy savings and/or electric utility peak-demand reduction resulting from each approved program and to conduct a program process evaluation of each approved program. Such person shall work at the sole direction of the commission staff.

(M) "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.

(N) "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.

(O) "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.

(P) "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.

(Q) "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.

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

(S) "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.

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

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

(V) "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.

(W) "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.

(X) "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.**

(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.**

(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.

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(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.**

(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:

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(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, prepared by the independent program evaluator, to measure and verify the energy savings and/or peak-demand reduction resulting from each program and to conduct process and impact evaluations of each program.

(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.**

(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 April 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 and demand reductions 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 for 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) A measurement and verification report from the independent program evaluator to verify the energy savings and peak-demand reduction projections utilized in the evaluation of 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 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. If the electric utility recommends program modification or elimination, it may propose an alternative program or programs to replace the eliminated program, 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. However, 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.

(D) 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.

(E) Banking surplus energy savings. To the extent that an electric utility's actual energy savings exceeds its energy efficiency benchmark for any year, the electric utility may apply such surplus energy savings to either its energy efficiency benchmarks for a subsequent year or toward meeting its advanced energy requirement, but not both. In order to exercise this option, the electric utility shall indicate in the annual portfolio status report for the year in which the surplus occurs whether the surplus will be directed to a subsequent year's energy efficiency benchmark or its advanced energy requirement.

(F) 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. 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.**

(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.**

(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 may, jointly with the electric utility, apply for exemption from such recovery as set forth in rule 4901:1-39-09 of the Administrative Code.

(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 **Commitment for integration by mercantile customers.**

(A) A mercantile customer may enter into a special arrangement with an electric utility, pursuant to division (A)(2)(d) of section 4928.66 of the Revised Code, to commit the customer's demand reduction, demand response, or energy efficiency projects for integration with the electric utility's demand reduction, demand response, and energy efficiency programs. Such arrangement shall:

(1) Address coordination requirements between the electric utility and the mercantile customer, including specific communication procedures and intervals.

(2) Specify the qualifying circumstances under which demand reductions may be effectuated by the customer.

(3) 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.

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

(B) The electric utility and mercantile customer shall file a joint application for approval of a special arrangement under this rule, which may include a request for an exemption from the cost recovery mechanism set forth in rule 4901:1-39-08 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:

(1) Baselines for the mercantile customer's kilowatt-hour consumption and peak demand based upon averages of the three most recent years of metered data or, if metered data is not available, based upon a reasonable method of estimation.

(2) The impacts on the mercantile customer's baseline kilowatt-hour consumption and baseline peak demand of the energy efficiency and peak-demand reduction projects be committed to the electric utility's energy efficiency and peak-demand reduction programs.

(3) An accounting of the incremental energy saved and incremental peak-demand reductions achieved in the most recent year by the mercantile customer's projects committed to the electric utility's program.

(4) A mercantile customer's energy savings and peak-demand reductions shall be calculated by subtracting the energy user and peak demand associated with the customer's projects from the estimated energy use and peak demand that would

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have occurred if the customer had used industry standard new equipment or practices to perform the same functions in the industry in which the mercantile customer operates. Kilowatt-hours of energy and kilowatts of capacity provided by electric generation sited on a mercantile customer's side of an electric utility's meter shall not be considered energy savings or reductions in peak demand.

(a) Such accounting shall distinguish between projects implemented before and after January 1, 2009, or in reports filed for years subsequent to 2009, before and after the most recent year.

(b) The report shall quantify the energy savings or peak-demand reductions of projects initiated prior to 2009 in the baseline period recognizing that projects may have diminishing effects over time as technology evolves or equipment degrades.

(c) The energy saving and demand reduction effects during the electric utility's baseline period of any mercantile customer, energy savings, or peak-demand reductions that are integrated into an electric utility's demand response, energy efficiency, or peak-demand reduction programs shall be 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.

(5) A listing and description of the customer projects 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.

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

(7) The timeline showing when each project or measure went into effect, and when the energy savings and peak-demand reductions took place.

(8) A copy of the formal declaration or agreement that commits the mercantile customer's projects for integration, including any requirement that the electric utility will treat the information provided 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.

(C) The joint application shall include a description of all methodologies, protocols, and practices used or proposed to be used in measuring and verifying project results. The joint application should also identify and explain all deviations from any guidelines that may be published for program measurement and verification of compliance.

(D) Any special arrangement under this rule may be combined with any other arrangement made pursuant to section 4905.31 of the Revised Code, if such arrangement contains appropriate measurements and verification of project results.

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4901:1-40-01 **Definitions.**

(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 by an electric utility or electric services company 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.

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(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 capable of supplying energy to the utility distribution system.

(M) "Double-counting" means utilizing renewable energy, renewable energy credits, or energy efficiency savings to (1) satisfy multiple regulatory requirements, (2) support multiple voluntary product offerings, (3) substantiate multiple marketing claims, or (4) some combination of these. Double counting includes the utilization of acquired, committed, utility-owned renewable energy resources if renewable energy credits for the generation of such resources can be separately transferred.

(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) "Fully aggregated" means that a renewable energy credit, as defined in this rule, shall retain all of its environmental attributes, including those pertaining to air emissions, and that specific environmental attributes are not separated from the renewable energy credit and sold individually. The credit may be unbundled from the electricity with which the credit was originally associated.

(U) "Geothermal energy" means hot water or steam extracted from geothermal reservoirs in the earth's crust and used for electricity generation.

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

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

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

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

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

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

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

(CC) "Renewable energy credit" means the fully aggregated environmental attributes associated with one megawatt hour of electricity generated by a renewable energy resource.

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

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

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

(GG) "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.

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

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

(JJ) "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.

(KK) "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.**

(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.**

(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%
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.

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(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.

4901:1-40-04 **Qualified resources.**

(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) 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.

(b) The amount of energy that may qualify from a storage facility is the amount of electricity dispatched from the storage facility and shall exclude the amount of energy required to initially pump the resource into the storage reservoir.

(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.

(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 maximum annual 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.

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(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. 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 subsequently 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) To be applied towards compliance, RECs shall remain fully aggregated.

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

(E) An entity seeking resource qualification shall first apply for certification of its resources or technologies. This 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) Application for such certification consists of completing and filing application forms as prescribed by the commission or its staff.

(2) Any interested person may file a motion to intervene in the proceeding and may request a hearing on the application.

(3) 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.

(4) 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.

(5) 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.

(6) 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.

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

(F) At its discretion, the commission may classify any new technology or additional resource as an advanced- or a 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.**

(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.**

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.**

(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.

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(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.**

(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.

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4901:1-40-09 **Annual report.**

(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.

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4901:1-41-01 **Definitions.**

(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) "Climate registry" means the international greenhouse gas measurement and reporting system, including accounting and verification measures, which provide voluntary or mandatory reporting requirements.

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

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4901:1-41-02 **Purpose and scope.**

(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.

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4901:1-41-03 **Greenhouse gas reporting and carbon dioxide control planning.**

(A) Any person 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, or as otherwise directed by the commission.

(B) Any person who 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.

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4901:5-1-01 **Definitions.**

As used in Chapters 4901:5-1 to 4901:5-7 of the Administrative Code:

(A) "Business office" means any office maintained by the reporting person where bills issued by the reporting person may be paid and discussed with its representatives.

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

(C) "~~EDU~~Electric utility" ~~means electric distribution utility and for the purpose of this chapter means an electric utility company that supplies at least retail electric distribution service to more than fifteen thousand customers within Ohio~~has the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(D) "Electric transmission owner" ~~for the purpose of this chapter~~ means the owner of a major utility facility as defined in section 4935.04 of the Revised Code.

(E) "Gas distribution line and associated facility" means a pipeline and associated facilities other than gathering or transmission line in a distribution area.

(F) "Gas gathering line and associated facility" means a pipeline and associated facilities which transport gas from a current production facility to a transmission line or main.

(G) "Gas or natural gas transmission line and associated facilities" has the meaning set forth in rule ~~4906-1-02~~ 4906-1-01 of the Administrative Code.

(H) "Long-term forecast report" has the meaning set forth in section 4935.04 of the Revised Code.

(I) "Major utility facility", has the meaning set forth in division (A)(1) of section 4935.04 of the Revised Code.

(J) "Person" has the meaning set forth in ~~sections~~ section 4906.01 ~~and 4935.04~~ of the Revised Code.

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

(L) "Substantial change" includes, but is not limited to:

(1) A change in forecasted peak loads or energy delivery over the forecast period of greater than an average of one-half of one per cent per year as calculated in rule 4905:5-3-03 of the Administrative Code.

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(2) The addition of a generating facility or facilities in an electric utility's supply plans.

~~(2)~~(3) **Demonstration of good cause to the commission by an interested party.**

(M) "Electric generating facility" means an electric generating plan and associated facilities capable of producing electricity.

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4901:5-1-02 **Form of long-term forecast report filing required.**

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 shall annually furnish a long-term forecast report to the commission for its review, in compliance with the rules set forth in this chapter.

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4901:5-1-03 **Form of long-term forecast reports additional requirements.**

(A) All long-term forecast reports shall be submitted pursuant to the requirements set forth in Chapter 4901:5-3 of the Administrative Code.

(B) All hard copies of long-term forecast reports must be bound. The binding may include either a hard or soft cover so long as it adequately secures the pages.

(C) All long-term forecast reports shall contain a listing of the libraries to which a letter of notification has been mailed, stating where available copies may be obtained.

(D) Each long-term forecast report shall include a statement, signed by the person responsible for the filing, that the document is true and correct to the best of his or her knowledge and belief.

(E) All long-term forecast reports shall contain a certificate of service, signed by the person responsible for its filing, stating that the requirements of paragraphs (F) to (I) of this rule will be met.

(F) On the same date a long-term forecast report is filed with the commission, the reporting person shall deliver or mail a copy of the long-term forecast report to the office of the consumers' counsel at their offices in Columbus, Ohio.

(G) Within three days of filing with the commission, a letter of notification shall be delivered or sent by first class mail by the reporting person to:

(1) The main public library of each county in Ohio which the reporting person services.

(2) The main public library of each county in Ohio in the area in which any portion of a major utility facility is to be located during the forecast period.

(H) The reporting person shall keep at least one copy of the person's current long-term forecast report at the person's principal business office in Ohio for public inspection during office hours.

(I) The reporting person shall provide or cause to be provided a copy of the person's long-term forecast report to any person upon request at cost to cover the expenses incurred.

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4901:5-1-04 **Notice of substantial change.**

(A) If the long-term forecast report to be furnished under division (C) of section 4935.04 of the Revised Code will contain a ~~"~~substantial change~~" as defined in division (D)(3)(e) of section 4935.04 of the Revised Code~~, the reporting person shall file a notice of substantial change with the commission forty-five days prior to the filing date of the long-term forecast report or as soon thereafter as the reporting person knows of the substantial change.

(B) Notice of substantial change shall consist of a letter, signed by the person responsible for filing the long-term forecast report, stating that a substantial change will be reflected in the forthcoming long-term forecast report~~ and identifying the provision of division (D)(3)(e) of section 4935.04 of the Revised Code which is applicable~~.

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4901:5-3-01 **Long-term forecast report due dates.**

(A) All electric transmission owners or ~~EDUs~~ 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 ~~as defined in section 4935.04 of the Revised Code~~, the electric transmission owner or the ~~EDU~~ 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 ~~EDU~~ 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 ~~4901:5-5~~ 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 ~~EDU~~ 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.

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4901:5-3-02 **Fees.**

(A) Fees for electric transmission owners or ~~EDUs~~ electric utilities shall be submitted annually to the commission ~~by~~ 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 ~~EDUs~~ 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 ~~FE3-T1~~ FE-T1 column twelve.

(2) For ~~EDUs~~electric utilities, the fee shall be two and one-half mills per megawatt-hour delivery based upon the ~~total~~ net energy for load for the most recent year for which actual data is reported on the most recently filed form ~~FE4-D1~~ 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.

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4901:5-3-03 **Calculation of forecast rates of change.**

(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 ~~EDUs~~ electric utilities, the rate of change shall be calculated based upon the ~~total~~ net energy ~~column~~ for load on form ~~FE4-D2 column eight. If form FE4-D2, is not filed, the calculation of rate of change shall be based upon the total energy column on form FE3-D1~~ 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 ~~EDUs~~electric utilities, the rate of change shall be based upon ~~EDU system~~ the electric utility's forecast of its seasonal peak load demand ~~forecast,~~ in Ohio as reported on form ~~FE4-D5. If form FE4-D5 is not filed, form FE4-D4 shall be employed to calculate the rate of change of peak loads. For electric transmission owners, the rate of change shall be calculated based upon form FE3-T2 electric transmission owner's system seasonal peak load demand forecast~~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.

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4901:5-5-01 **Definitions.**

~~The following definitions apply to this chapter:~~

(A) "ATC" means available transfer capability~~and is the portion of total transfer capacity remaining in the physical transmission system for further commercial activity over and above already committed wholesale and retail uses~~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.

~~(B)~~(G) ~~"ECAR" identifies an electric reliability council or a successor organization, which functions within a geographic area that includes Indiana, Ohio, and parts of Kentucky, Maryland, Michigan, Pennsylvania, Tennessee, West Virginia, and Virginia. The electric utility systems in this area that are engaged in the generation, transmission, and sale of electric power and energy are the parties to a formal agreement entitled, "East Central Area Reliability Coordination Agreement" or a similar agreement of a successor organization~~"Electric transmission owner" means the owner of a major utility facility as defined in section 4935.04 of the Revised Code.

~~(C)~~(H) ~~"EEI" means Edison electric institute~~"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.

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

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

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~~(F)~~(K) "Integrated operating system" means a group of electric transmission owners or ~~EDUs~~ 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.

~~(G)~~(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.

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

~~(I)~~(U) ~~"Service area," means the geographic area in which the electric transmission owner or EDU renders service to wholesale or retail consumers of energy~~"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.

~~(J)~~(Y) "Transfer capability," means the ~~capability~~ ability of the ~~electric transmission owner or EDU's~~ owner's system to ~~deliver or transfer power from all points of receipts to all delivery points~~move power over its system to another interconnected transmission system or distribution utility while meeting all national standard reliability requirements.

~~(K)~~(Z) "TTC" means total transfer capacity ~~and is the amount of electric power that can be transferred from one control area to another over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post-contingency system conditions. TTC is the lesser of the network transfer capability or contract path capacity (i.e., the sum of capacities of all interconnections to a neighboring control area)~~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.

4901:5-5-02 **Purpose and scope.**

(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.

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4901:5-5-03 **Forecast report requirements for electric utilities and transmission owners.**

(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.

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(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.

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(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.

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(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.**

(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.

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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:

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(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.**

(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 **Integrated resource plans for electric utilities.**

(A) The integrated resource plan shall contain a narrative discussion and analysis of:

(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.

(B) Existing generating system description.

(1) The reporting person shall provide a brief summary narrative of the existing electric generating system (which is detailed in paragraph (E)(1) of this rule). 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.

(2) 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 and reconciled with the information required in paragraph (E)(2) of this rule.

(C) Need for additional electricity resource options.

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(1) 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) 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 sell power.

(h) Price responsive demand and price elasticity, including, but not limited to, the value of lost load assessments due to the voluntary implementation of time differentiated pricing.

(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.

(2) A discussion of the electric utility's projected system reliability, including the projected adequacy of the existing system in both the short- and long-term.

(D) Integrated resource plan.

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(1) 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.

(2) A discussion of the electric utility's projected system reliability shall be presented. It shall include:

(a) A discussion of the future adequacy of the electric utility's projected system in both the short- and long-term.

(b) 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.

(3) 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.

(4) 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:

(a) A general discussion of the decision-making process, criteria, and standards employed by the electric utility as it relates to the development of the integrated resource plan.

(b) 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.

(c) A discussion of key assumptions and judgments used in development of the integrated resource plan.

(5) The reporting person shall provide information sufficient for the commission to determine the reasonableness of the integrated resource plan. In determining the reasonableness of an integrated resource plan, the commission will consider:

(a) The adequacy, reliability, and cost-effectiveness of the plan.

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(b) 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.

(c) Whether the plan gives adequate consideration to the following factors:

(i) Uncertainty in load forecasts and electricity resource option cost, availability, and performance estimates.

(ii) Potential rate and customer bill impacts of the plan.

(iii) Environmental impacts of the plan and their associated costs.

(iv) Other significant economic impacts and their associated costs.

(v) Impacts of the plan on the financial status of the company.

(vi) Other strategic considerations including flexibility, diversity, the size and lead time of commitments, and lost opportunities for investment.

(vii) Equity among customer classes.

(viii) The impacts of the plan over time.

(d) Such other matters the commission considers appropriate.

(E) Electricity resource forecast forms. The electricity resource forecast shall be submitted in an electronic form prescribed by the commission or its staff.

(1) 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.

(2) 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.

(3) 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."

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(4) 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. The following forms shall be provided.

(a) Form FE-R4: "Actual Generating Capability Dedicated to Meet Ohio Peak Load."

(b) 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.

(c) 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.

(d) 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.

(e) 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.

(f) 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.

(5) 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."

(a) 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.

(b) 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.