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 Amended Substitute Senate Bill No. 221.	)	Case No. 08-888-EL-ORD

ENTRY ON REHEARING

The Commission finds:

(1) 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, to address energy efficiency and alternative energy resources, renewable energy credits, clean coal technology, and environmental regulations.

(2) On April 15, 2009, the Commission issued its opinion and order (April 15 Order) adopting three new chapters of the Ohio Administrative Code (O.A.C.): Chapter 4901:1-39: Energy Efficiency and Demand Reduction Benchmarks, Chapter 4901:1-40: Alternative Energy Portfolio Standard, and Chapter 4901:1-41: Greenhouse Gas Reporting and Carbon Dioxide Control Planning. The April 15 Order also modified relevant forecast rules contained in Chapters 4901:5-1, 4901:5-3, and 4901:5-5, O.A.C.

(3) Section 4903.10, Revised Code, provides that any party who has entered an appearance in a Commission proceeding may apply for rehearing with respect to any matters determined by filing an application within 30 days after the entry of the order upon the journal of the Commission.

(4) On May 15, 2009, applications for rehearing were filed by the Solid Waste Authority of Central Ohio (SWACO); the city of Hamilton, Ohio; Industrial Energy Users-Ohio (IEU); the Kroger Co. (Kroger); American Municipal Power-Ohio, Inc. (AMP-Ohio); Constellation NewEnergy, Inc., Direct Energy Services, LLC, and Integrys Energy Services, Inc. (collectively, Competitive Suppliers); FirstEnergy Service Company, on

behalf of affiliated companies FirstEnergy Solutions Corp., FirstEnergy Generation Corp., FirstEnergy Nuclear Generation Corp., and FirstEnergy Nuclear Operating Company (collectively, FESA); the FirstEnergy Corporation operating companies, Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company (FirstEnergy); Buckeye Power, Inc. (Buckeye); Duke Energy Ohio, Inc. (Duke); the Ohio Energy Group (OEG); the American Electric Power Company operating companies, Columbus Southern Power Company and Ohio Power Company (AEP); the Ohio Consumer and Environmental Advocates (OCEA); the Ohio Hospital Association and the Ohio Manufacturers' Association (OHA/OMA); and the Dayton Power and Light Company (DP&L). Memoranda contra were timely filed by Kroger, AMP-Ohio, FESA, FirstEnergy, the Competitive Suppliers, AEP, IEU, the Ohio Environmental Council (OEC), OCEA, and Duke.

(5) These parties raise a number of assignments of error associated with the rules that the Commission adopted by the April 15 Order. In this entry, the Commission will address the assignments of error raised, which we believe warrant modification to the rules that we have adopted or where further clarification or discussion is needed. To the extent an allegation of error is raised that is not directly addressed herein or not incorporated in the rule modifications that we adopt, it has been rejected. Consideration of the applications for rehearing will be addressed under the relevant chapter and rule sections as adopted in the April 15 Order.

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

Rule 39-01 Definitions

(6) Rule 39-01 contains the definitions for Chapter 4901:1-39. We first note that several clerical corrections have been made so that the terms appear in alphabetical order.

39-01(E) Capital stock

(7) Duke characterizes the definition of "capital stock" in 39-01(E) as impossible to understand. The Commission notes that "capital stock" is a term of art that describes the collective aggregation of machinery and equipment requiring energy. In

its "Assumptions to the Annual Energy Outlook 2008," the Energy Information Agency of the U.S. Department of Energy, uses the term "capital stock," noting that "[t]he energy intensity of the new capital stock relative to 2002 capital stock is reflected in the parameter of the technology possibility curve estimated for the major production steps for each of the energy intensive industries."[1] The term "capital stock" refers to equipment whose efficiency will be improved in order for an electric utility to meet its benchmark. "Capital stock" includes, but is not limited to, all boilers, motors, lighting fixtures, home furnaces, and air conditioners.

39-01(I) Economic potential

(8) The term "economic potential" which is now renumbered as 39-01(G) has been corrected to delete the phrase "commercially available" to be consistent with our definitions of "achievable potential" and "technical potential," and will now read as follows:

> "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,~~ AND cost-effective measures. Economic potential is a subset of the "technical potential."

39-01(L) Independent program evaluator

(9) Several intervenors argue that the Commission should alter the definition of "independent program evaluator" in Rule 39-01(L) to indicate that the Commission will choose the independent program evaluator, thereby removing a potential conflict of interest. DP&L argues that this provision is not a cost-effective or appropriate approach. DP&L argues that this arrangement sets up an inherently confrontational process, as each electric utility will likely want to hire its own program evaluator, and if there are multiple evaluators for each electric utility, there will be duplicative expenses and possibly conflicting sets of recommendations. DP&L contends that this situation will drive up costs and drain resources that could better be used to

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1 http://www.eia.doe.gov/oiaf/archive/aeo08/assumption/industrial.html

fund programs to achieve demand response and energy efficiency savings. Instead, DP&L argues that if there is to be a consultant who is directed solely by staff, then the Commission should go through normal state of Ohio procurement requirements necessary to hire such an individual. If the Commission then wants to assess utilities for the costs of that consultant, it has the power to do so.

The Commission believes that the process for selecting and hiring an independent program evaluator should mirror the long-established process currently used to select and hire external auditors in gas GCR cases and similar proceedings. The Commission intends to rely on one independent evaluator which is directed by staff. The Commission recognizes that electric utilities will need to include measurement and verification (M&V) activities and budgets in their program portfolio plans, and such prudently incurred costs may be recoverable. In the instance where an electric utility has already hired a consultant prior to the effective date of the rules, and the electric utility's consultant provides value to the Commission or staff, the Commission will take that into consideration when the electric utility seeks cost recovery. Upon review of this provision, we have made the following clarification to Rule 39-01(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~~ AS DIRECTED BY THE COMMISSION. Such person shall work at the sole direction of the commission staff.

(10) DP&L also proposes that the "program process evaluation" should be performed once initially, and only performed thereafter if there is reason to believe that a management audit is necessary. DP&L contends there should be no form of ongoing annual process review. The Commission rejects this argument. The manner in which programs are implemented on an ongoing basis is integral to their success. DP&L asserts that in the context of Rule 39-05(C)(2)(c), addressed below, the

electric utilities need flexibility to adjust programs quickly in order to adapt to market conditions. We believe, however, that ongoing process audits will assist the Commission in determining the reasonableness of those adjustments when cost recovery for such adjustments is contemplated.

39-01(O) Nonenergy benefits

(11) OCEA argues that the Commission should adjust the definition of "nonenergy benefits" in Rule 39-01(O) to incorporate a standard method for calculating those benefits, namely, the societal test, when evaluating the effects of externalities in approving portfolio program plans. OCEA argues that the societal test should be employed because it evaluates parameters that are not taken into account under the total resource cost test (TRC).

As noted above, this definition has been renumbered as Rule 39-01(P). The Commission believes that the definition of "nonenergy benefits" should not be limited to societal benefits that can be readily quantified and calculated using the societal test. Under Rule 39-03, electric utilities may propose and the Commission may approve programs, including programs that may not pass the TRC test, based on consideration of the programs' nonenergy benefits. Accordingly, the Commission believes that changing this definition is unwarranted.

39-01(Q) Peak-demand benchmark

(12) AEP argues that the use of the words "must achieve" in Rule 39-01(Q) and the corresponding language in Rule 39-05(C) requiring an electric utility to report "its achieved energy savings and demand reductions" do not comport with SB 221, which refers to "... programs *designed* to achieve peak demand reductions..." (Emphasis added). AEP contends that the peak-demand reduction benchmarks should be met by virtue of programs that are designed to meet them, whether or not peak demand is actually reduced.

The Commission believes that the benefits of SB 221 cannot be realized unless real peak-demand reductions are realized. The baselines and benchmarks will be known in advance. The day-ahead forecast demand will dictate whether, and the degree to which, interruptions must be called or not called in order to achieve the benchmarks. If interruptible customers cannot accept the prospect of being interrupted, service should be sought under another tariff, supplier, or operations so as to mitigate demand during peak hours. If the electric utilities cannot rely upon interruptible customers to reduce peak demand, they should seek to implement real peak-demand reductions through other means.

Rule 39-03 Program planning requirements

(13) Rule 39-03 addresses program planning requirements for electric utilities' energy efficiency and peak-demand reduction program portfolio plans. AEP argues that the detail required in Rule 39-03 constitutes micromanagement of electric utilities in their compliance efforts, and could potentially have a chilling effect on the types of programs that may be considered by electric utilities since even rejected programs would be subject to review.

The planning process provides for transparency and meaningful participation by stakeholders in determining the appropriate program mix and whether an electric utility is doing all that it can. The Commission strongly believes in the value of such public vetting. In such a context, after-the-fact review of rejected programs will be minimized by publicly reviewing programs in advance.

In addition, Section 4928.66(A)(2)(b), Revised Code, allows the Commission to adjust benchmarks due to regulatory, economic, or technological reasons beyond an electric utility's control. Our belief is that the statutory benchmarks represent the minimum requirement, and that a rigorous planning process is the only way to determine whether better efficiency can be achieved, or whether an electric utility has exhausted all reasonable opportunities for achieving energy efficiency.

(14) Duke requests clarification of the meaning of the requirement in Rule 39-03(A)(1) to "survey and characterize the energy-using capital stock" located within the electric utility's certified territory. Our intent is for the electric utility to survey and estimate the number and various kinds of devices and equipment using energy in its service area. In conducting the survey, we expect the electric utility will be able to sort and classify those devices by vintage and usage pattern (e.g., how

many hours does equipment typically run in a particular end-use sector or subsector), and by the corresponding levels of efficiency as currently exist. The objective is to develop as keen a sense as possible for the potential of energy efficiency to conserve kilowatt-hours.

We note that some existing customer equipment or processes may not fall into neat, generic categories such as motors or lighting. The intent behind the provision is for electric utilities to describe such equipment and processes to the best of their ability in order to estimate how much energy use may not be subject to deemed savings associated with readily commercially available replacement technologies. The characterization process of all of the electricity use in an electric utility's service area will aid in the planning process, and will assist the Commission and stakeholders in determining the programs necessary to achieve maximum kilowatt-hour savings and peak-demand reductions.

Rule 39-04 Program portfolio plan and filing requirements

(15) Rule 4901:1-39-04 addresses the requirements for electric utilities' comprehensive energy efficiency and peak-demand reduction program portfolios. AEP asserts that the development of M&V guidelines and/or protocols is critically important to ensuring that electric utilities collect the appropriate data and plan programs, and are ultimately able to meet their guidelines.

The Commission is keenly aware of and sensitive to the development of M&V guidelines, including a technical reference manual of deemed savings for standard, off-the-shelf measures, and for the process of auditing custom measures and programs. We believe it is important that there be consistency among electric utilities as to deemed savings to the extent that there are no climate differences in play, and that a single set of protocols apply to all.

There are, however, practical limitations to the rate at which we can proceed. Therefore, we intend to initiate, a statewide collaborative process to address both standard and custom program situations. To this end, we have opened a docket, Case No. 09-512-GE-UNC, and will be issuing an entry in the near future in that docket, which will establish a process to develop protocols for the M&V of energy efficiency and peak demand reduction measures and create a technical reference manual. Additionally, to facilitate the design and filing of the electric utilities' Rule 39-04 program portfolio plans, as well as the review of such plans, the Commission and its staff are creating a template for the program portfolio plans that will be posted on the Commission's website. To assist in the creation of the template, a draft template will be issued for stakeholder comment by a subsequent entry in a separate docket

<u>Rule 39-05 Benchmark and annual status reports</u>

(16) Rule 39-05 identifies requirements for benchmark and annual status reports. Duke requested clarification of the term "trend analysis" included in Rule 39-05(C)(2)(a)(i). As used in this rule, we mean a reasoned quantitative assessment of how anticipated savings will be realized over future time periods. To clarify our intent of the rule, we will modify this provision as follows:

> 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~~ OF HOW ANTICIPATED SAVINGS WILL BE REALIZED OVER the life of the program.

(17) Rule 39-05(C)(2)(b) specifies the parameters of a report from an independent program evaluator, including M&V of data from the previous calendar year. Duke contends that more time is required for the development of such a report, especially for studies that rely upon billing analyses that can require a full year of load-impact results due to the installation of weather-sensitive measures. Duke requests that the Commission recognize that results from M&V studies should and will evolve over time.

The Commission recognizes Duke's concerns. We are cognizant of the fact that complete verification may not occur until one or two years after an electric utility files for recovery of program expenses. Thus, we recognize that any annual reconciliation pursuant to Rule 39-06 may be delayed until a complete verification is available.

We also clarify that the Commission intends that, to the greatest extent practicable, annual reports should verify the actual program impacts, which occurred during the calendar year under review. When measures are implemented during a year, only the savings from the time of implementation until the end of the year count for purposes of meeting the benchmark. Various arguments have been raised regarding the impacts of partial-year measures, and that they should be extrapolated to count as though the measure had been in place for a full year.

We see verification issues with the approach of extrapolating a partial year to a full year. We are, therefore, clarifying that the measured and verified impacts of an energy efficiency measure will be counted over a full year's time. If that full year spans two calendar years, the kilowatt-hour savings accrued in the first year shall count toward the first year's benchmark, and the kilowatt-hour savings in the second year shall count toward the second year's benchmark.

(18) As noted above, DP&L contends that a more streamlined approach is necessary than that described in Rule 39-05(C)(2)(c), so that electric utilities have the flexibility to adjust their program and funding mix as they learn what programs and measures work well in their respective service areas. DP&L is concerned that the regulatory lag created by this rule could cause electric utilities to miss a benchmark.

DP&L's arguments are well taken. The ability to adjust programs in real time may improve overall performance and may mean the difference between meeting a benchmark and paying an assessment. This need for an efficient process of adjusting programs and budgets must, however, be balanced against the need for a public vetting process and Commission oversight. We will, therefore, provide two levels of flexibility. First, electric utilities can seek staff's written approval to shift funding and/or change the program mix so long as the impacts are less than 25 percent of the program portfolio budget for the customer class. If program and/or budget allocation adjustments exceed 25 percent of the program portfolio plan budget, electric utilities will be at risk for recovery of expenditures associated with program adjustments until such time as the program changes or budget adjustments are approved by the Commission. Such approval may be requested in the company's next portfolio review under Rule 39-04(E), or in the annual benchmark status report proceeding under Rule 39-05(C). In any case, we will require that any program adjustments be noticed to all parties in the proceeding required by Rule 39-04(E) in which the program portfolio plan was approved, and any party may file an objection and request a hearing of the issues or a staff determination. Accordingly, Rule 39-05(C)(2) will be amended as follows:

(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:

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(c) A recommendation for whether each program should be continued, modified, or eliminated. The electric utility may propose alternative programs to replace eliminated programs, taking into account the overall balance of programming in its program portfolio plan. The electric utility shall describe any alternate program or program modification by providing at least the information required for proposed programs in its program portfolio plan pursuant to this chapter. An electric utility may seek written staff approval to reallocate funds between programs serving the same customer class at any time, provided that the reallocation supports the goals of its approved program portfolio plan and is limited to no more than twenty-five per cent of the funds available for programs serving that customer class. IN ADDITION, AN ELECTRIC UTILITY MAY

> **CHANGE ITS PROGRAM MIX OR BUDGET ALLOCATIONS AT ANY TIME, AS LONG AS IT PROVIDES NOTICE TO ALL PARTIES IN THE PROCEEDING IN WHICH THE PROGRAM PORTFOLIO PLAN WAS APPROVED.**

(19) Several intervenors object to the limiting nature of Rule 39-05(D), and to various complexities it creates regarding which measures can be counted toward benchmarks, as well as when they may be counted. We will clarify that the impact of measures installed before a new technical standard takes effect will be counted. However, the adoption of measures which, at the time of their installation, were required by law or regulation will not be counted. The Commission may, however, address the program mix in the electric utility's next portfolio review proceeding, allowing for due process and hearing, as provided by Rule 39-04(E).

(20) We will also clarify that the "double counting" prohibition in Rule 39-05(D) narrowly applies to standards set by law or regulation that create specific technical performance standards and do not apply to general mandates or benchmarks for energy efficiency and peak-demand reduction like those contained in SB 221. Additionally, if federal energy efficiency standards are adopted that are not technology- or device-specific, but rather specify percentage savings objectives with regard to a baseline, impacts from electric utility programs should be counted towards both state and federal standards. If such legislation is enacted, the Commission will provide specific guidance on whether and how programs under this rule shall be counted. We will, however, clarify Rule 39-05(D) as follows:

> 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, ~~**and applicable to specific devices or technologies,**~~ including, but not limited to, those embodied in the Energy Independence and Security Act of 2007, or an applicable building code.

(21) With respect to Rule 39-05(E), DP&L argues that SB 221 permits double counting of energy-efficiency impacts for both energy-efficiency benchmarks and advanced energy benchmarks because the definition of advanced energy benchmark includes "demand-side management and any energy-efficiency improvement." We disagree. The requirements are separate in the law, and not duplicative. In the absence of specific language allowing double counting of energy-efficiency impacts towards both energy efficiency and advanced energy benchmarks, we believe it is contrary to the purpose and policy of SB 221 to interpret the law permissively with regard to such double counting.

Rule 39-06 Annual reports and commission verification report

(22) Chapter 4901:1-39-06 addresses procedures for the review of annual reports and the issuance of the Commission verification report. IEU characterizes Rule 39-06 as unreasonable because it provides no opportunity for parties to file comments on the staff report.

While we acknowledge IEU's concern, the staff report already takes into account stakeholder comments on the substantive content of the subject report. There are three opportunities to comment on the achieved savings: (1) after the initial portfolio status report is filed by the electric utility; (2) if the staff recommends forfeiture; and (3) if staff does not recommend forfeiture, but the Commission sets the matter for hearing. In commenting on the electric utility's portfolio status report, stakeholders have an opportunity to support or disagree with the electric utility's description of implementation or characterization of compliance or claimed achievements on a program-by-program basis. We do not find it necessary to mandate an additional opportunity for parties to file comments, particularly since nothing would preclude a stakeholder from requesting a hearing should circumstances warrant additional review. We believe this provision affords all stakeholders a reasonable opportunity for due process.

(23) With regard to Rule 39-06(B), OCEA argues that the law clearly requires the Commission to impose a forfeiture as a consequence of an electric utility's noncompliance with statutory energy efficiency or peak-demand reduction

benchmarks, but makes no express provision for the imposition of remedial action.

The Commission recognizes the obligation to assess a forfeiture in the case of unjustifiable noncompliance, but we believe the law does not preclude this Commission from directing that remedial or even preventive measures be taken under the appropriate circumstances.

Rule 39-07 Recovery mechanism

(24) Rule 39-07 provides a process by which an electric utility may request recovery of an approved rate adjustment mechanism that will be reconciled annually. AEP contends that the requirement that an electric utility's program portfolio plan be approved prior to commencement of cost recovery should be eliminated. AEP also argues that the Commission should explicitly authorize carrying charges if it retains the regulatory lag approach.

The Commission has no intention of preapproving cost recovery for programs that have not yet been determined to be reasonable and cost-effective. The issue of carrying costs will be addressed on a case-by-case basis.

(25) With respect to Rule 39-07(A)(1), Kroger advances a number of arguments relating to transmission and distribution investments that achieve energy efficiencies. First, Kroger argues that an electric utility has an incentive to favor investments in transmission and distribution energy efficiency to the exclusion of customer end-use energy efficiency investments.

We see no merit in this argument. As we have previously stated in the April 15 Order, the energy efficiency benchmarks represent the minimum energy efficiency savings required by Section 4928.66(A)(a)(a) of the Revised Code. As 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. Energy efficiency minimum benchmarks accumulate to more than 22 percent by 2025. The least efficient transmission and distribution systems in Ohio lose far less than 22 percent of the energy generated. It appears, therefore, highly unlikely that utilities can even meet the minimum benchmarks through transmission and distribution energy efficiency investments to the exclusion of customer energy efficiency programs. Even if the minimum benchmarks could be achieved, the utility would have failed in its obligation imposed within these rules to deploy all cost-effective energy efficiency

(26) Second, Kroger reasons that the recovery mechanism for transmission and distribution energy efficiency investments should be separate from customer energy efficiency program expenditures because electric utilities will have a greater incentive to invest in transmission and distribution energy efficiency, than in customer end-use energy efficiency. Moreover, transmission and distribution investment recovery is available to an electric utility without a rate case. Kroger argues that such separate recovery mechanism for transmission and distribution energy efficiency investment should include a demand charge, noting that costs imposed by customers for transmission and distribution services are proportional to customers' demand for capacity.

Kroger's arguments ignore an important mitigating phrase included in Rule 39-07(A)(1) which states that recovery of transmission and distribution energy efficiency expenditures is limited to the extent the investment was made for energy efficiency purposes. In addition, transmission and distribution energy efficiency programs will need to go through the planning and review processes in Rules 39-03 and 39-04. While we note that the incentives and circumstances for transmission and distribution energy efficiency investments are different from customer energy efficiency investments, they are not so different as to warrant a separate cost-recovery mechanism. Each transmission and distribution energy efficiency program will be considered in the program portfolio plan proceeding, and can be distinguished therein from customer energy efficiency programs. Therefore, we decline to modify the rule as suggested by Kroger. We will, however, correct a clerical error, Rule 39-07(A)(2) has been modified as follows:

> 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 4901:1-39-08 of the Administrative Code.

(27) Kroger posits that electric utilities will recover lost transmission and distribution revenues associated with transmission and distribution energy efficiency investments.

We note that because the transmission and distribution energy efficiency improvements are upstream of the customer's meter, there are no lost transmission and distribution revenues associated with transmission and distribution energy efficiency investments. These investments do not reduce kilowatt-hour sales to customers as customer energy efficiency programs are designed to do.

(28) Duke requests clarification of whether the Commission will entertain a partial exemption in Rule 39-07(A)(2). Given that the rule does not limit the Commission's discretion in determining this issue, we see no reason to modify it at this time. We intend to address the question of partial exemption on a case-by-case basis.

(29) OCEA seeks clarification that mercantile customers must still contribute to lost distribution revenues because mercantile customers contribute to an electric utility's lost distribution revenues in the same way that other customers do.

To the extent lost distribution revenues result from any customer energy efficiency programs, including mercantile customer programs, the electric utility may seek recovery. With regard to the outcome of any such recovery that may be granted, the Commission intends that mercantile customers will be treated the same as other customers.

<u>Rule 39-08 Commitment for integration by mercantile customers</u>

(30) Kroger argues that the communications requirement in Rule 39-08(A)(1) is vague and could lead to burdensome requirements for detail.

We will address any such burden on a case-by-case basis. We will, however, clarify that the specific communications requirement applies to demand reductions that are not pursuant to an electric utility program.

(31) Several parties argue that mercantile customers should be able to initiate their own proceedings to commit their customer-sited capabilities for integration under Rule 39-08.

We agree that mercantile customers should be permitted to initiate their own proceedings to commit their resources for integration with utility energy efficiency and peak demand reduction programs under Rule 39-08. To address these concerns, paragraphs A and B of Rule 39-08 will be modified as follows:

(A) A mercantile customer **MAY FILE, EITHER INDIVIDUALLY OR JOINTLY WITH AN ELECTRIC UTILITY, AN APPLICATION** ~~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, **PURSUANT TO DIVISION (A)(2)(D) OF SECTION 4928.66 OF THE REVISED CODE**. Such arrangement shall:

(1) Address coordination requirements between the electric utility and the mercantile customer **WITH REGARD TO VOLUNTARY REDUCTIONS IN LOAD BY THE MERCANTILE CUSTOMER, WHICH ARE NOT PART OF AN ELECTRIC UTILITY PROGRAM OR TARIFF**, including specific communication procedures

....

(B) The application to commit a mercantile customer project for integration ~~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~~ **4901:1-39-07** of the Administrative Code....

(32) Kroger submits that since an electric utility receives the benefit of benchmark reduction, the electric utility should pay for the cost of M&V required under Rule 39-08.

As discussed above, the Commission intends to employ a similar process for approving independent M&V evaluators as we have traditionally used in fuel audit cases. Although the Commission ultimately selects the independent evaluator who becomes answerable to the Commission, any such external contractors are paid for by the electric utility and, as with the Commission itself, the costs must ultimately become subject to recovery from all ratepayers. Likewise, if an electric utility retains a consultant to assist with M&V activities, and the costs of such consultant are part of an approved budget, such costs that are prudently incurred will be subject to recovery.

(33) With regard to 4901:1-39-08(B), several parties objected to the case-by-case approach and the burdensome detail associated with approving exemptions for mercantile customers from the energy efficiency rate mechanism. However, sufficient information about equipment change-out is required to measure and verify savings. Therefore, while we are sensitive to the burden on mercantile customers, we believe it will be most appropriate to conduct a case-by-case analysis before granting an exemption, at least until a technical reference manual for deemed and/or calculated savings can be developed. Moreover, the Commission intends to use electronic processing to lessen reporting burdens and solicit stakeholder input to streamline exemption application processing where appropriate.

(34) With respect to Rule 39-08(B)(3), Kroger argues that requiring additional tracking mechanisms to verify the amount of energy saved will increase the cost of a project, thus decreasing the rate of return for implementing a project. Kroger notes that this could result in otherwise beneficial energy saving projects not being pursued by a mercantile customer because such projects are no longer cost effective once the costs of regulatory compliance are considered.

Rule 39-08(B)(3) pertains only when a mercantile customer applies to integrate its own efficiency project into a utility program, and seeks an exemption from paying its share of the electric utility program costs. Where a mercantile customer seeks to integrate a project that is outside of the utility's tracking mechanisms, an accounting of incremental energy saved and incremental peak-demand reductions is needed to ensure the utility's compliance with statutory benchmarks. Customers, however, should recognize that insufficient documentation may result in delay or denial of an exemption. We also note that, as discussed above, the Commission will be developing a technical reference manual for M&V of savings, which may better address practical or specific tracking concerns.

(35) Numerous parties commented on the requirement included in Rule 39-08(B)(4) that only those kilowatt-hours that are incremental to "industry standard new equipment or practices to perform the same function" shall count in the calculation of a mercantile customer's kilowatt-hour savings.

We are not persuaded by comments that the gross amount of savings between replaced and replacement equipment should count.

(36) Several parties also argue that, under Rule 39-08(B)(4), on-site generation facilities should be allowed to be counted as peak demand-reduction measures for mercantile customers. We note that many customer-sited generation technologies will count under the renewable or advanced categories. We will consider other customer-sited generation technologies on a case-by-case basis, and may further address these issues in the development of the technical reference manual discussed above.

(37) IEU objects to the requirement of Rule 39-08(B)(4)(b) that an electric utility's annual benchmark report recognize the diminishing effects of evolving technologies or equipment degradation. IEU argues that SB 221 contains no provision that permits such a diminution of efficiency savings over time. Additionally, IEU posits that Rule 39-08(B)(4)(b) is unreasonable inasmuch as it arbitrarily presumes diminishing

returns and omits any specification on how this alleged degradation is to be derived.

A degradation effect exists both in terms of actual efficiency and in terms of the advancing state of the art, as better and more cost-effective equipment becomes available. We will, publish M&V procedures in the technical reference manual discussed above that provide a calculation of the degradation factor.

(38) Kroger suggests that Rule 39-08(B)(6) be deleted, arguing that the Commission should only require a general listing of a mercantile customer's energy savings projects. Kroger contends that there is no legitimate need for a mercantile customer to provide the cost of its energy savings programs.

In order to establish that a measure meets the TRC test, one must know the cost of such measure. Moreover, Kroger makes no compelling argument for treating mercantile energy efficiency measures any differently than electric utility sponsored energy efficiency measures. And since all cost-effective, energy efficiency measures should be pursued, cost of mercantile customer projects are relevant to the Commission's inquiry. As noted above, incomplete information in an application to commit customer-sited programs for integration into utility programs will risk delay or denial of such commitment and any associated exemption from a rate mechanism. Programs that do not meet the TRC test will be considered on a case-by-case basis, and may rely on nonenergy benefits in order to be approved as part of a program portfolio plan or an application to commit for integration.

Chapter: 4901:1-40 Alternative Energy Portfolio Standard

Amendments in HB 2

(39) On April 1, 2009, Governor Stickland signed into law Amended Substitute House Bill No. 2 (HB 2), which amends Sections 4928.64 and 4928.65, Revised Code, with respect to the definition of alternative energy resources and the calculation of a renewable energy credit (REC) to be derived from certain generating facilities. These amendments, which become effective on July 1, 2009, add as a possible category of alternative energy resources any renewable energy resource

created on or after January 1, 1998, by the modification or retrofit of a generating facility placed in service before January 1, 1998.

HB 2 also modifies the SB 221 requirement that one REC equals one megawatt-hour of electricity derived from a renewable energy resource. HB2 will allow more than one REC to be created for each megawatt-hour of energy produced by an Ohio generating facility of 75 megawatts or greater that has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable generation principally from biomass energy by June 30, 2013. Specifically, the act provides that the energy so generated cannot equal less than one REC and can equal more, based on a formula. The REC value is obtained by multiplying the actual percentage of biomass feedstock heat input used to generate such megawatt-hour by the quotient obtained by dividing the then-existing alternative compliance payment by the then-existing market value of one REC.

At least one Ohio utility is planning such a facility. In an April 1, 2009, press release, First Energy Corporation announced plans, which require federal approval, to convert two generating units at its R.E. Burger plant in Shadyside, Ohio from coal-fired to principally using biomass feedstock for energy generation.[2]

(40) As the HB 2 amendments will become effective on July 1, 2009, before the Commission's rules in this proceeding become effective, changes to Rules 40-01(CC), 40-04(A)(10), and 40-04(E) are necessary to conform the definition of a REC and an eligible alternative energy resource with the new statutory language. These changes will be specifically addressed in considering the respective rules below.

Green Pricing Program & REC Issues

(41) Both AEP and DP&L raise issues with respect to green pricing programs and the RECs associated with them. DP&L believes that RECs purchased by customers under its green pricing program should count towards an electric utility's compliance

2 *See*, Final Bill Analysis of HB 2 under Public Utilities Commission, Alternative energy at http://www.lsc.state.oh.us/analyses128/09-hb2-128.htm.

with the alternative energy portfolio standard (AEPS) requirements under Section 4928.64, Revised Code, while AEP argues that unused RECs purchased under its green pricing program should be eligible for inclusion in the electric utility's AEPS report.

The use of RECs purchased and consumed under an electric utility's separate green pricing program for that utility's AEPS compliance would constitute double-counting of these RECs in violation of Rule 40-04(D)(4). The electric utility's green pricing programs were optional, customer-sponsored programs to support renewable generation. It would be deceptive to these customers who voluntarily purchased green pricing blocks monthly under the green pricing programs to have these RECs also diverted to support electric utility compliance with the AEPS. If, however, an electric utility purchased RECs as part of its green pricing program, and those RECs were never subscribed by customers (i.e., not consumed), those RECs could be applied toward AEPS compliance provided that such RECs satisfy all the requirements in Chapter 4901:1-40.

(42) DP&L contends that electric utilities should be able to seek a waiver if REC prices are high but are still within the three percent cost cap.

The statute contains two provisions by which an electric utility or electric service company may be excused from meeting a required benchmark, that being force majeure or reaching a cost cap. There is no additional statutory direction concerning the scenario proposed by DP&L. Unless a cost cap is triggered or an event of force majeure can be proven, the Commission would expect the benchmarks to be realized.

Rule 40-01 Definitions

40-01(F) Clean coal technology

(43) The competitive suppliers argue that the term "clean coal" used in this definition should be amended to refer to "processed" rather than "clean" coal.

The Commission disagrees with this recommendation, as "clean coal technology" is the language that appears in Section 4928.01(A)(34), Revised Code.

40-01(G) Co-firing

(44) OCEA argues that any co-firing application must also consider the efficiency of the boilers. It is OCEA's position that certain boilers are not as efficient when utilizing some portion of biomass feedstock, for instance, and this efficiency should be considered.

The Commission does not support this recommendation in the context of the AEPS requirements. The statutory definition in Section 4928.01(A)(35), Revised Code, does not require a consideration of boiler efficiency. Accordingly, we will not change the "co-firing" definition.

40-01(I) Deliverable into this state

(45) Multiple parties commented on the definition of "deliverable into this state." While their specific arguments varied, the central theme was that the parties believe it is unnecessary to require a demonstration of deliverability for facilities located within PJM or MISO territory. The required load flow and/or deliverability studies are characterized as unnecessary, burdensome, costly, and of little to no value. It was also mentioned that RECs from a wider geographic range may include less expensive renewable options. Proposed solutions included a rebuttable presumption of deliverability, the development of a generic staff analysis of deliverability from various locations, and, most prominently, an assumption that any resource within PJM or MISO be considered deliverable.

The Commission continues to believe that it is inappropriate to offer a blanket presumption of deliverability for any and all facilities within PJM or MISO. The rule as currently drafted reflects a reasonable balance between regulatory efficiency and maintaining the deliverability requirement explicit under Section 4928.64(B)(3), Revised Code. The rule does not automatically prohibit participation by facilities in certain geographical locations and, therefore, it does not necessarily limit access to certain resources that may be competitively priced.

The required load flow study and/or deliverability study required of facilities in noncontiguous states is expected to be part of a one-time review. The study need only demonstrate that some portion of the facility's generation is capable of being physically delivered to the state. Upon reconsideration, this definition will be revised to read as follows:

> "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.

40-01(L) Distributed generation

(46) OCEA suggested a modification to the definition of "distributed generation" to more clearly indicate that ownership of the equipment does not determine eligibility. In particular, OCEA suggests language to more clearly incorporate systems owned by the customer or a third-party. SWACO also requests that the definition be amended to include systems that are attached to the electric grid but perhaps not capable of supplying electricity to the system based solely on on-site generation versus usage (i.e., no excess).

This definition is silent on the issue of equipment ownership and, therefore, is not limited exclusively to customer-owned equipment. A third-party arrangement, as hypothesized by OCEA, would not be precluded from consideration. The Commission agrees with the revision suggested by SWACO and has revised the definition accordingly, to read as follows:

> "Distributed generation" means electricity production that is on-site and is ~~capable of supplying energy~~ CONNECTED to the ~~utility distribution system~~ ELECTRICITY GRID.

40-01(M) Double counting

(47) Numerous comments were submitted regarding the definition of "double counting." The electric utilities argue that efficiency efforts under Section 4928.66, Revised Code, should also satisfy advanced energy requirements under Section 4928.64, Revised Code. They argue that the statute does not expressly contain any explicit prohibition against counting the same energy

efficiency or peak-demand reduction program savings against both energy efficiency requirements while also counting toward AEPS compliance. Such double counting should be permitted, they claim, to reduce overall compliance costs and thereby benefit ratepayers. DP&L also requests that language be added to the rule addressing the coordination of potential federal alternative energy requirements.

AEP also argues that peak-demand reductions associated with certain renewable technologies should be recognized under Section 4928.66, Revised Code, while the renewable facility itself would count toward AEPS compliance under Section 4928.64, Revised Code. AEP acknowledges, however, that efficiency gains would not count under both sections as the rule is currently structured.

As discussed at pages 28-29 of our April 15 Order, we believe that it would be inappropriate to count efficiency efforts under both Section 4928.66, Revised Code, and the advanced energy requirements under Section 4928.64, Revised Code. No new arguments have been raised on rehearing. As stated in the order, this Commission does not believe it is appropriate to recognize the specific benefits of these activities under both requirements simultaneously.

40-01(T) Fully-aggregated RECs

(48) IEU, AMP-Ohio, and the Competitive Suppliers seek rehearing to remove the requirement that RECs must be fully aggregated, arguing that disaggregated RECs may be cheaper and, therefore, could lower compliance costs. AMP-Ohio suggests this definition should be amended to allow the portion of a REC associated with greenhouse gas destruction (i.e., via flaring or other combustion) to be separate from the portion of the REC associated with the generation of renewable energy. AMP-Ohio also requests that the nitrogen oxide (NOx) set-aside allowances associated with a renewable facility be recognized separately from the REC.

Section 4928.65, Revised Code, discusses the use of RECs but does not expressly address the issue of aggregation. The parties requesting rehearing on this topic all advocate a less stringent definition than that adopted by the Commission. While we are not ruling on the merits of allowing NOx set-aside allowances allocated to renewable facilities as part of the state's NOx Budget Trading Program to be separated from the REC at this time, any party may seek a waiver of a Commission rule that will be decided on a case-by-case basis. With respect to disaggregating the potential carbon offsets from a REC, the Commission will revisit this rule in the event that state or federal carbon mandates are enacted.

40-01(U) Geothermal energy

(49) DP&L believes the definition of "geothermal energy" is not appropriate given the resources in the region, and proposes a new definition. IEU also contests the proposed definition and argues it needs to include other applications that do not necessarily result in the generation of electricity.

The Commission does not believe that a change to this definition is warranted. To the extent that other electricity-generating applications of geothermal technology are being considered, the Commission will be processing applications for resource qualification as part of the certification process initiated in Rule 40-04(F). Further, Rule 40-04(G) provides a mechanism by which the Commission may classify a new technology or additional resource as an advanced or a REC.

40-01(CC) Renewable energy credit

(50) IEU argues that the Commission should use the statutory definition for "renewable energy credit" in Section 4928.65, Revised Code, which does not contain any restriction on aggregation. IEU contends that it is therefore unreasonable to include such language in the rule.

As previously discussed, the Commission does not believe that the lack of an express statutory directive prohibits us from adopting reasonable regulations for the aggregation of RECs. We, therefore, reject IEU's argument, but will modify this provision to reflect the HB 2 amendments so as to conform this definition with the newly amended statutory language described above, as follows:

> "Renewable energy credit" means the fully aggregated environmental attributes associated with one megawatt-hour of electricity generated

by a renewable energy resource, EXCEPT FOR ELECTRICITY GENERATED BY FACILITIES AS DESCRIBED IN PARAGRAPH (E) OF RULE 4901:1-40-04 OF THE ADMINISTRATIVE CODE.

Rule 40-03 Requirements

40-03(A)(2)(a) In-state provisions

(51) AEP argues that the in-state provision should not apply on an annual basis, but rather only by 2025. AEP believes that enforcing this requirement on an annual basis is not supported by the statutory language and reduces compliance flexibility. AEP concludes that an in-state provision, if applied annually, should recognize the current availability of renewable resources in Ohio.

DP&L argues that the in-state provision does not apply to the solar carve-out, but rather to the overall renewable requirement. DP&L requests that the rule be adjusted to reflect this consistent with SB 221.

The city of Hamilton and AMP-Ohio also believe this language needs to be modified to recognize additional hydroelectric facilities as "in-state resources." Specifically, they suggest that the rule be amended to recognize in-state hydroelectric facilities "within or bordering this state or within or bordering an adjacent state."

(52) The Commission declines to adopt the proposed changes to this rule. The annual in-state provision, both for solar and non-solar renewable energy resources, is consistent with the statutory benchmark design and objectives. With regard to the comments of AMP-Ohio and the city of Hamilton, the Commission believes that the rule in its current form accurately reflects the statutory provision in terms of what constitutes an in-state hydroelectric facility.

40-03(A)(3) Bypassability of compliance costs

(53) DP&L contends that this provision is too broad and should be amended to reflect the possibility for a nonbypassable surcharge pursuant to Section 4928.143, Revised Code. Section 4928.64(E), Revised Code, provides:

> All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code.

We believe that Rule 40-03(A)(3) is consistent with this statutory language and should not be revised. The Commission does, however, acknowledge the statutory language referenced by DP&L in its comments. By virtue of being recovered through a nonbypassable surcharge, as permitted by Section 4928.143, Revised Code, those particular costs would not be considered compliance costs in the context of Section 4928.64, Revised Code. Therefore, it would not be appropriate to address these costs under Rule 40-03(A)(3).

<u>**40-03(B)(1) Electric utility baseline calculation**</u>

(54) OCEA argues that the baseline should not be a function solely of standard service offer sales, but rather should also include other types of sales, such as special contracts and reasonable agreements. OCEA argues that limiting the baseline to standard offer sales is inconsistent with SB 221 and serves to reduce the baseline calculation.

Section 4928.64(B), Revised Code, specifies that the generation provided by electric utilities from alternative energy sources be a portion of the electricity supply required for its standard service offer and, therefore, sales outside of the standard service offer sales may not be included in the baseline calculation. To the point raised by OCEA, standard service offer sales would include sales under special contracts or reasonable agreements and, therefore, these sales would be part of the baseline calculation.

<u>**40-03(C) Portfolio standard planning document**</u>

(55) DP&L contests this requirement, particularly as it pertains to timing. Given the number of filing requirements due on April 15, DP&L suggests staggering the filing requirements or requiring biennial filings for longer-term planning documents. The competitive suppliers argue that a 10-year planning horizon is unrealistic given the uncertainties in their operations and, therefore, suggest a one-year planning horizon for electric

service companies. FirstEnergy objects to the imposition of any planning document as unduly burdensome, costly, and not required by the statute.

The Commission does not find merit in the arguments raised on this topic and will retain this provision in its current form. We believe this particular requirement is important for our review of Ohio's progress in meeting statutory AEPS requirements.

<u>**Rule 40-04 Qualified resources**</u>

<u>**40-04(A)(8) Storage facility qualifications**</u>

(56) FirstEnergy argues that this definition is unreasonably narrow and not consistent with SB 221. FirstEnergy contends that such an interpretation fails to recognize the true value of storage facilities in a renewable context, and any limiting language should be deleted.

The Commission agrees that a storage facility, depending on its application, may offer energy management, reliability, and power quality benefits in the ability to store off-peak generation for use during peak periods. However, electricity storage does not automatically constitute a renewable energy resource unless the electricity storage is achieved by the use of renewable electricity generation. Accordingly, we decline to adopt the proposed modification.

<u>**40-04(A)(10) & 40-04(E) HB 2 Amendments**</u>

(57) As discussed above, this rule will be modified to reflect the HB 2 amendments in two places. The first modification is the addition of a new subsection (10) to Rule 40-04(A), as follows:

> 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:
>
> ***
>
> **(10) A RENEWABLE ENERGY RESOURCE CREATED ON OR AFTER JANUARY 1, 1998, BY THE MODIFICATION**

> OR RETROFIT OF ANY FACILITY PLACED IN SERVICE PRIOR TO JANUARY 1, 1998.

The second change is the addition of a new paragraph 40-04(E), which reads as follows:

> FOR A GENERATING FACILITY OF SEVENTY-FIVE MEGAWATTS OR GREATER THAT IS SITUATED WITHIN THIS STATE AND HAS COMMITTED BY DECEMBER 31, 2009, TO MODIFY OR RETROFIT ITS GENERATING UNIT OR UNITS TO ENABLE THE FACILITY TO GENERATE PRINCIPALLY FROM BIOMASS ENERGY BY JUNE 30, 2013, THE NUMBER OF RECS PRODUCED BY EACH MEGAWATT-HOUR OF ELECTRICITY GENERATED PRINCIPALLY FROM BIOMASS ENERGY SHALL EQUAL THE ACTUAL PERCENTAGE OF BIOMASS FEEDSTOCK HEAT INPUT USED TO GENERATE SUCH MEGAWATT-HOUR MULTIPLIED BY THE QUOTIENT OBTAINED BY DIVIDING THE THEN-EXISTING UNIT DOLLAR AMOUNT USED TO DETERMINE A RENEWABLE ENERGY COMPLIANCE PAYMENT AS PROVIDED UNDER DIVISION (C)(2)(B) OF SECTION 4928.64 OF THE REVISED CODE, BY THE THEN-EXISTING MARKET VALUE OF ONE REC, BUT SUCH MEGAWATT-HOUR SHALL NOT EQUAL LESS THAN ONE CREDIT.

<u>40-04(C) Mercantile customer-sited resources</u>

(58) The Competitive Suppliers contest this section of the rule in that it limits the use of mercantile customer-sited resources to electric utilities only. They argue that competitive providers ought to also be able to utilize such resources since they too have requirements under the AEPS. IEU also contests the "double counting" aspect of this rule. IEU argues that mercantile resources should be permitted to count towards both the energy efficiency and peak-demand reduction commitments in Section 4928.66, Revised Code, and the advanced energy requirements in Section 4928.64, Revised Code.

The Commission rejects the arguments raised because we believe it is appropriate to restrict this particular provision to use by electric utilities since it is the electric utilities' systems into which the resources would be integrating. However, we note, as discussed more fully below, that Rule 40-04(D)(1) provides a mechanism by which electric service companies can use RECs from mercantile customer-sited resources.

40-04(D) REC eligibility

(59) IEU contests this language as it pertains to mercantile customer-sited resources, indicating that such resources should not be bound by the terms of Rule 40-04(A), particularly the placed in-service date.

The Commission acknowledges that mercantile customer-sited resources need not meet the January 1, 1998 placed in-service date, provided that the resource is also committed for integration into an electric utility's demand-response, energy efficiency, or peak-demand reduction program. This provision is conveyed in Rule 40-04(C) and has been retained. The language in question above addresses mercantile customer-sited resources that have not been integrated into the electric utility's programs previously described. Adding this language to Rule 40-04(D)(1) provides greater opportunities for mercantile customer-sited resources to participate, rather than limits them, as implied by IEU. Therefore, the Commission declines to modify Rule 40-04(D)(1).

(60) FirstEnergy argues that the deliverability requirement does not apply to RECs and, therefore, should be removed from the rule as this deliverability limitation will increase compliance costs. Similarly, both the city of Hamilton and AMP-Ohio argue that Section 4928.65, Revised Code, does not include a placed in-service date provision and, therefore, it is inappropriate to apply a placed in-service requirement on RECs. They argue that placed in-service is not a relevant consideration for RECs.

The Commission believes that Section 4928.65, Revised Code, must be read in the context of the preceding Section 4928.64, Revised Code. Accepting RECs without any consideration of deliverability or placed in-service, as argued by these parties, would essentially nullify much of Section 4928.64, Revised Code. In addition, Section 4928.65, Revised Code, makes specific reference to the renewable energy and solar energy resource requirements in Section 4928.64(B)(2), Revised Code, further reinforcing the appropriateness of interpreting these sections in concert.

With respect to Rule 40-04(D)(2)(c), Duke requests guidance on how another tracking system would be recognized by the Commission. The rule permits participation in an alterative attribute tracking system that has been approved by the Commission, other than PJM's generation attributes tracking system or MISO's renewable energy tracking system. Such participation may be accomplished by filing an application requesting approval for the use of the alternative tracking system. For clarification, this provision will be modified to read as follows:

> (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.

40-04(D)(3) REC life

(61) Duke argues that this language should be modified so that RECs have a 5-year life from the time that the associated electricity is generated. They believe this would clarify the regulatory treatment for forward purchases and would also eliminate the potential for RECs with an infinite life.

The Commission finds no reason to modify Rule 40-04(D)(3) given our interpretation of Section 4928.65, Revised Code. In terms of forward purchases, we believe that the 5-year period would commence when the purchaser received the RECs. Starting the 5-year clock at the time a forward purchase is entered into could potentially result in the future stream of

RECs expiring before the RECs are even generated, which seems to be an unreasonable result.

40-04(D)(6) RECs from no earlier than July 31, 2008

(62) IEU and FirstEnergy contest this provision as not supported by the statute. IEU and FirstEnergy refer to Section 4928.65, Revised Code, in concluding that the July 31, 2008, requirement is unlawful and unreasonable.

The Commission finds it unreasonable to give credit for RECs generated prior to the effective date of SB 221, given that the statute does not expressly permit the use of RECs associated with electricity generated prior to the effective date of the law. Therefore, we conclude that this provision is not inconsistent with the statute, and that the recognition of older RECs is inconsistent with the purpose of the legislation.

40-04(E) Resource certification

(63) We first note that, due to the addition of a new provision to reflect the HB 2 amendments, this paragraph will be renumbered as Rule 40-04(F).

OCEA suggests that this process should be expedited for certain types of resources where a more streamlined review may be acceptable. DP&L argues that a 60-day timeframe is not realistic given the way the REC market operates, with a need for a quick turnaround when evaluating potential transactions. DP&L also believes that, given where we are already in 2009, a certification process could lead to even greater regulatory delays. DP&L suggests that waivers for 2009 and perhaps 2010 may be necessary depending on when the certification form is made available.

IEU interprets Rule 40-04(E) as potentially not applying to stand-alone generators, separate from a compliance plan, and concludes that this falls short of the statutory requirement. IEU believes the proposed certification process is unnecessary as qualified resources are already defined in the statute. IEU contests the value of the certification process in that the rules indicate that such certification does not convey a Commission position on compliance and/or cost recovery.

(64) With regard to the OCEA argument, the Commission has elected to not specify a streamlined process for particular resources. However, the rule, as currently designed, would not prohibit the Commission from issuing a certificate in less than 60 days. The rule will be revised to clarify the appropriate timeframe for persons seeking intervention and ensure due process.

In response to IEU, we believe that the certification process does apply to stand-alone generators. In fact, the Commission expects stand-alone generators to constitute a significant percentage of applicants. These facilities may seek certification well in advance of entering into negotiations with potential buyers, with such an approach alleviating the potential delays implicit in DP&L's comments.

The certification process will focus largely on three statutory criteria: (1) the resource/technology employed, (2) the placed in-service date, and (3) deliverability. Verifying that these three considerations are satisfied will ensure that the resource or technology is consistent with the requirements of the alternative energy portfolio standard.

Accordingly, the process under this provision will be modified to mirror that recently adopted by this Commission for special arrangements under Chapter 4901:1-38, O.A.C., to read as follows:

(E) An entity seeking resource qualification shall ~~**first apply**~~ FILE AN APPLICATION for certification of its resources or technologies, **UPON SUCH FORMS AS MAY BE PRESCRIBED BY THE COMMISSION. THE APPLICATION** ~~**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.**~~

(1~~2~~) Any interested person may file a motion to intervene **AND FILE COMMENTS AND OBJECTIONS TO ANY APPLICATION FILED UNDER THIS RULE WITHIN**

TWENTY DAYS OF THE DATE OF THE FILING OF THE APPLICATION~~ in the proceeding and may request a hearing on the application.~~

The Commission is working toward making an online certification process available as soon as these rules become effective. However, we are also cognizant of the urgency for stakeholders to certify alternative generation facilities as soon as possible, notwithstanding the lack of codified rules during the pendency of the rule adoption process. Accordingly, the Commission will, with the issuance of this entry, publish an application form and instructions for the certification of generation facilities as Ohio Renewable Energy Resources. The form and instructions may be accessed at:

http://www.puco.ohio.gov/puco/forms/

Applicants may begin filing applications for certification immediately and, where appropriate, the Commission may grant certification by order prior to the effective date of these rules.

40-04(E)(5) Commission Certification

(65) As noted above, this provision will be renumbered as Rule 40-04(F)(4). OCEA suggests that a certified facility be granted RECs from the date of the first commercial operation of the system. DP&L argues that any certification program should recognize RECs back to July 1, 2008. In addition, Duke seeks clarification as to whether the Commission would recognize RECs generated from a facility prior to it being certified.

The Commission believes that it is appropriate to recognize RECs back to July 31, 2008, provided that the facility was a participant in an existing attribute tracking system during that time or had a meter in place which can accurately demonstrate generation levels from July 31, 2008, forward. Such a policy is contingent upon the attribute tracking systems' acceptance of historical RECs. In addition, consistent with the Commission's policy on double counting expressed in this rule, the Commission will not retroactively recognize any past RECs, which have been sold or otherwise consumed.

<u>40-04(E)(6) Revocation of Certification Status</u>

(66) With respect to this provision, which has been renumbered as Rule 40-04(F)(5), Duke seeks clarification as to what would occur in the event of a certificate revocation. Specifically, Duke inquires whether such a revocation would impact historical RECs from such a facility, or only be applied on a prospective basis.

In the case of certificate revocation, the Commission clarifies that it would recognize otherwise-qualified RECs from a facility up to the point of revocation.

<u>Rule 40-07 Cost caps</u>

<u>40-07(A)&(B) Separate renewable and advanced energy cost caps</u>

(67) Both IEU and DP&L contest the Commission's interpretation that two cost caps are appropriate. Both parties argue that the concept of two caps is unreasonable and not supported by statute.

The Commission continues to believe that the most reasonable interpretation of the language of Section 4928.64(C)(3), Revised Code, results in the initiation of two separate cost caps. This topic was previously addressed in our April 15 Order at 37, and no new arguments have been raised on rehearing. Therefore, we decline to make any modifications to this rule.

<u>40-07(C) Cost cap calculation</u>

(68) FirstEnergy contends this portion of the rule is unreasonable and not supported by SB 221. FirstEnergy believes that the statutory language on this topic is clear and that the calculation should consist of a marginal or incremental approach rather than a focus on total generation costs.

The Competitive Suppliers also argue that this requirement does not recognize the different pricing structures offered by competitive providers, specifically that a cost of generation may not be readily discernible. The Competitive Suppliers request a different approach for electric service companies in terms of evaluating whether the three percent cost cap has been reached.

(69) The Commission has considered numerous possible interpretations in the context of the cost caps, including that proposed by FirstEnergy. However, the Commission has concluded that an incremental or marginal approach is not appropriate. Our April 15Order at 37, specifically addressed this issue:

> 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.

With regard to the Competitive Suppliers, the Commission notes that the burden of proof remains with the electric service companies if seeking a determination that the applicable cost cap has been reached. As part of this demonstration, an electric service company may file information that it believes is relevant for the Commission's consideration.

<u>40-07(D) Exclusion of costs as part of unavoidable surcharge</u>

(70) IEU argues that it is unlawful to exclude costs in an unavoidable surcharge from consideration as a cost of compliance. IEU believes these costs must be considered in terms of the cost cap or, otherwise, the proposed rule would permit affected entities to select the most expensive compliance options and then exclude them from the cost cap.

The issues raised on this topic in rehearing were previously addressed at page 38 of our April 15 Order. 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. As previously stated, our intention is that costs for which a nonbypassable surcharge have been approved should be included in the calculation of the expected generation rate.

However, such 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. The Commission finds no reason to modify this section of the rule on rehearing.

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

Rule 41-01 Definitions

(71) Rule 41-01 sets forth the definition of terms used in this chapter. AEP and Duke argue that the Commission should modify its definition of the term "climate registry." They contend that the definition is unclear and needs to be modified to clarify whether the definition is referring to a specific climate registry, or any climate registry that meets the wording of the definition. The Commission finds that clarification of the definition is warranted. We have modified the definition to read as follows:

> (C) "THE Climate Registry" means the ~~international greenhouse gas measurement and reporting system, including accounting and verification measures, which provide voluntary or mandatory reporting requirements.~~ NONPROFIT COLLABORATION AMONG NORTH AMERICAN STATES, PROVINCES, TERRITORIES AND NATIVE SOVEREIGN NATIONS, USING THE WEBSITE AT WWW.THECLIMATEREGISTRY.ORG, THAT SETS CONSISTENT AND TRANSPARENT STANDARDS TO CALCULATE, VERIFY, AND PUBLICLY REPORT GREENHOUSE GAS EMISSIONS INTO A SINGLE REGISTRY.

(72) AEP, Buckeye, IEU, FESA, and AMP-Ohio argue that the definition of "person" should not be used when determining what entities are required to comply with the reporting requirements under Rule 41-03. They assert that the Commission should use the term "public utility" instead of "person." They contend 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.

These parties argue that the reporting requirements under Rule 41-03 should be limited to public utilities that are subject to the Commission's jurisdiction which, they assert, would not include electric cooperatives, municipal electric utilities, and generation facilities owned by anyone other than public utilities. They argue that Sections 4905.02 and 4905.03, Revised Code, determine the appropriate jurisdictional public utilities to be regulated under these rules.

(73) Upon reconsideration, the Commission finds that the use of the term "person" in this chapter should be deleted and the term "public utility" should be inserted in its place. The Commission notes, however, that Chapter 4928, Revised Code, does not include a definition of public utility. Accordingly, the Commission will define one for purposes of Chapter 4901:1-41. The Commission, in defining the term "public utility," believes it is appropriate not only to look at the definition of "public utility" used in Sections 4905.02 and 4905.03, Revised Code, but also the definitions of jurisdictional entities set forth in the electric restructuring statutes, specifically Chapter 4928, Revised Code, where the greenhouse gas emission report requirements reside.

(74) Section 4905.02, Revised Code, in part, defines a public utility "as used in this chapter" as an "electric light company" as defined in Section 4905.03, Revised Code. An electric light company is defined as a company "engaged in the business of supplying electricity for light, heat, or power purposes to consumers within this state...." Section 4905.02, Revised Code, goes on to exclude certain types of electric light companies from the Commission's jurisdiction, namely electric light

companies not for profit and those owned or operated by municipal corporations. The Commission finds that in adopting a definition of "public utility" for purposes of Chapter 4901:1-41, to comply with Section 4928.68, Revised Code, the Commission must also consider other definitions of jurisdictional entities created in Section 4928.01, Revised Code, such as "electric utility" and "electric services company." Both of these definitions incorporate the term "electric light company," but distinguish between the type of electric services each of these entities provide, such as competitive verses noncompetitive retail electric services. Taking into consideration the changes that have occurred in the structure of the electric utility industry in this state and all the definitions used to define companies providing various electric services, we do not believe that it is appropriate to use only the definition of "public utility" set forth in Section 4905.02, Revised Code, as the reference for a definition of public utility to be used in Rule 41-01. Accordingly, the Commission shall establish the following definition of "public utility" for purposes of Chapter 4901:1-41, which we believe is consistent with, and comports with the intent of, Section 4928.68, Revised Code:

> ~~"Person" has the meaning set forth in section 4906.01 of the Revised Code.~~ "PUBLIC UTILITY" MEANS THOSE ENTITIES INCLUDED WITHIN THE DEFINITION OF "PUBLIC UTILITY" SET FORTH IN SECTION 4905.02 OF THE REVISED CODE, OR WITHIN THE DEFINITION OF "ELECTRIC SERVICES COMPANY" SET FORTH IN SECTION 4928.01 OF THE REVISED CODE.

(75) Adopting the above definition of "public utility" will require those entities that own electric generating facilities in the state and supply electricity to consumers, but excluding electric cooperatives and municipal electric utilities, to comply with Chapter 4901:1-41. Although this chapter, as modified, does not require electric cooperatives and municipal electric utilities to participate in The Climate Registry or file an environmental control plan with the Commission, the Commission will request that they voluntarily do so, as such participation may impact federal funding of the State's efforts in the reporting, verification, or regulation of greenhouse gas emissions.

Rule 41-03 Greenhouse gas reporting and carbon dioxide control planning

(76) Rule 41-03 sets forth the requirements for public utilities, as defined in this chapter, to participate in The Climate Registry and file an annual environmental control plan with the Commission. In its application for rehearing, DP&L argues that paragraph (A) of this rule should be clarified so that the phrase "or as otherwise directed by the Commission" applies to both the requirement to become a member in The Climate Registry and to report emissions, and not to just the reporting of emissions. To remove the ambiguity and to clarify that the phrase applies to both, the Commission has rewritten the paragraph to read as follows:

> UNLESS OTHERWISE DIRECTED BY THE COMMISSION, ANY PUBLIC UTILITY ~~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~~.

(77) Also with regard to this rule, AEP, Duke, and DP&L argue that, with the adoption of this rule, the electric utilities will be duplicating reporting efforts for certain greenhouse gas emissions that are currently required under other federal and state laws. They also assert that the United States Environmental Protection Agency (USEPA) is in the process of proposing rules that will require facilities emitting 25,000 metric tons or more per year of greenhouse gas to submit annual reports. They argue that the Commission should hold off adopting rules or permit electric utilities to comply with USEPA finalized greenhouse gas monitoring rules in lieu of the Commission's rules.

While the Commission is aware of the USEPA rulemaking process, those rules are far from being finalized. Further, those draft rules do not absolve the Commission of its responsibilities to create its own reporting requirements under Section 4928.68, Revised Code. At such time as the USEPA completes its process and provides the necessary clarity and direction in reporting requirements of greenhouse gases, the Commission will consider any necessary changes to its rules.

(78) Lastly, AEP contends that the Commission's rule goes beyond the requirements of Section 4928.68, Revised Code, by requiring the submission of an environmental control plan. AEP argues that SB 221 grants the Commission the authority to adopt rules establishing carbon dioxide control planning requirements but does not require the submission of an environmental control plan. The Commission finds no merit to AEP's argument. The statute requires the Commission to adopt rules establishing greenhouse gas emission reporting, including carbon dioxide control planning. The Commission finds that the submission of an environmental control plan is essential in carrying out the requirements of the statute.

Modifications to Long-Term Forecast Rules in Chapters 4901:5-1, 4901:5-3 and 4901:5-5

(79) In considering changes to the Commission's existing forecast rules in response to SB 221, the Commission initially considered making sweeping changes to all of the forecast chapters to conform these rules to updated rule structure and conventions. However, given the urgency in adopting rules to implement SB 221, we are only changing those provisions deemed critical to accomplish the purposes of the statute. We do note, however, that the gas and electric forecast rules are due to be reviewed in 2010 pursuant to Section 119.032, Revised Code, and we expect to make substantial modifications in that proceeding.

Rule 5-1-02 Form of long-term forecast report filing required

(80) We also note the intervention and application for rehearing of FESA, the FirstEnergy affiliated generation companies, who appear to believe that our changes to the forecast rules will now apply to them. The Commission recognizes that the statutory authority for the filing of a long-term forecast report (LTFR) has changed and does not include electric generation facilities under the definition of a "major utility facility" in Section 4935.04(A)(1)(a), Revised Code. Moreover, Section 4928.05(A)(1), Revised Code, exempts competitive retail electric service providers from forecast reporting. Since Rule 5-1-02, which establishes which entities are required to file LTFRs, does not take into account the enactment of Section 4928.05(A)(1), Revised Code, we find it appropriate to revise

the rule. Accordingly, we have revised Rule 5-1-02 to read as follows:

> EXCEPT FOR ELECTRIC SERVICES COMPANIES EXEMPTED PURSUANT TO DIVISION (A)(1) OF SECTION 4928.05 OF THE REVISED CODE, 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.

Rule 5-5-06 Integrated resource plans for electric utilities

(81) AEP, FirstEnergy, and Duke contend that the Commission has no authority to require an annual and detailed integrated resource plan (IRP) filing in the LTFR, and urge that Rule 5-5-06 should be deleted in its entirety. They argue that SB 221 does not require the reinstatement of rules for an IRP as part of an annual LTFR filing, and that 1999's Amended Substitute Senate Bill No. 3 (SB 3) removed resource planning and generation from the filing requirements. AEP acknowledges the Commission's interest in resource planning, particularly in light of the enactment of Sections 4928.64 and 4928.66, Revised Code, but AEP contends that the rules go far beyond the general description of the resource plan contemplated in Section 4935.04(C)(1), Revised Code.

OCEA argues that the IRP requirements for electric utilities under Rule 5-5-06 are critical to the Commission's function under SB 221. OCEA asserts that the electric utilities' arguments regarding Commission authority ignore both the overall policy and specific provisions of SB 221. OCEA points out that an IRP is critical because it is the only context in which the Commission can determine whether the actions of the electric utilities under Sections 4928.64 and 4928.66, Revised Code, will ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced electric service.

(82) The requirements for an annual filing of a resource plan in the LTFR are clearly specified in Section 4935.04(C), Revised Code:

> Each person owning or operating a major utility facility within the state or furnishing gas, natural gas, or electricity directly to more than fifteen thousand customers within this state annually shall furnish a report to the commission for its review. The report shall be termed the long-term forecast report and shall contain: (1) A year-by-year, ten-year forecast of annual energy demand, peak load, reserves, and a general description of the resource plan to meet demand....

Section 4935.04(D), Revised Code, sets forth certain conditions under which the Commission must hold a hearing on a long-term forecast report; and Section 4935.04(E)(2)(b), Revised Code, provides that the focus of the hearing shall include, but not be limited to, a review of the estimated installed capacity and supplies to meet the projected load requirements. Section 4935.04(F)(5), Revised Code, identifies the specific resource plan requirements to be considered in the Commission's determinations:

> (F) Based upon the report furnished pursuant to division (C) of this section and the hearing record, the commission, within ninety days from the close of the record in the hearing, shall determine if: ....
>
> (5) Utility company forecasts of loads and resources are reasonable in relation to population growth estimates made by state and federal agencies, transportation, and economic development plans and forecasts, and make recommendations where possible for necessary and reasonable alternatives to meet forecasted electric power demand....

(83) The IRP will include the alternative energy requirements that are specified in SB 221 and it will include the energy efficiency and peak demand response programs and their impacts that are also required in SB 221. Each person furnishing electricity directly to more than fifteen thousand customers within Ohio - namely all electric distribution utilities in Ohio - shall file this annual forecast report that shall include a resource plan. Each

of these electric utilities is required to annually file a ten-year forecast of energy demand, peak load, reserve, and a resource plan that enumerates how they intend to meet those demands. Rule 5-5-06 is consistent with current law and will facilitate the analysis and planning considerations of the new requirements as specified by SB 221.

<u>IRP should be submitted, not filed, to avoid constant litigation</u>

(84) AEP contends that an IRP should be submitted rather than filed to avoid constant litigation. AEP suggests that the IRP could be made available to interested parties who wanted to conduct their own analysis and make their own recommendations to the Commission, but AEP asserts that the constant litigation from an annual IRP filing would create an unreasonable burden for its staff responsible for conducting AEP's resource planning.

The Commission believes that the elimination of an open, public review of the IRP would inhibit the due process protections embedded in our rules and law. If there is information filed in an IRP that the electric utilities believe should be protected, they can file a motion for a protective order. Under Section 4935.04(D)(3), Revised Code, the Commission must have a public hearing every five years, or sooner if a substantial change is triggered. An interested party can request a forecasting hearing if the party can demonstrate good cause. To demonstrate good cause, it is essential that all interested parties have access to information that details the energy demand, peak load, reserve, and resource plan. Additionally, Section 4935.04(C), Revised Code, requires the LTFR to be furnished to the Commission, not merely submitted to staff as suggested by AEP.

The law only requires a hearing every five years. In rare occurrences a hearing may occur sooner when there is a substantial change. But this hardly rises to the characterization of constant litigation. Additionally, unless there is a change in forecast methodology or assumptions, electric utilities are only required to submit annually the forms and not the entire set of data sources, methodologies, and assumptions utilized in deriving the forecasts.

(85) AEP also complains that Rule 5-5-06 requires duplicative information involving litigation from other proceedings to be filed as part of the IRP. AEP suggests that, if the Commission requires an annual IRP filing, the sections of the IRP that will result in the relitigation of any issues should be removed.

The issue raised by AEP does not accurately characterize the use of this data in preparing a forecast and the Commission's determinations on the demand forecast and resource plan. The Commission makes determinations about the accuracy of information used in the LTFR. If the information used as an input in the forecast was addressed in a Commission order in another case, it will likely result in a pro forma determination of this information's accuracy. There is no requirement that it be relitigated as suggested by AEP.

<u>**Rule 5-1-01(L) Substantial hange**</u>

(86) AEP argues that the definition of "substantial change" in Rule 5-1-01(L) is improper because it refers to energy "delivery," while the statutory definition in Section 4935.04(D)(3)(c)(i), Revised Code, refers to energy "consumption." AEP contends that the addition of a generating facility or facilities in an electric utility's supply plans should be removed from the definition, and suggests that the definition of substantial change be made consistent with the statute.

The Commission agrees with AEP and will revise the definition of "substantial change" in Rule 5-1-01(L) to read as follows:

> "Substantial change" includes, but is not limited to:
>
> (1) A change in forecasted peak loads or energy ~~**delivery**~~ CONSUMPTION over the forecast period of greater than an average of one-half of one per cent per year as calculated in rule 4905:5-3-05 of the Administrative Code.
>
> ~~**(2) The addition of a generating facility or facilities in an electric utility's supply plans.**~~
>
> (~~3~~2) Demonstration of good cause to the commission by an interested party.

While we are revising the rule to more closely follow the statute, the Commission notes that the "substantial change" definition includes a good cause provision. To the extent an electric utility plans a new generating facility that will be used to serve Ohio load, such facility would constitute a "substantial change"under this rule, and should be reported in the resource section of the LTFR. Consequently, an IRP would be included in the electric utility's LTFR, and would trigger a hearing.

(87) In addition to the above change to this rule, a clerical error will be corrected in Rule 5-1-01(M), which will be revised to read as follows:

> "Electric generating facility" means an electric generating ~~plan~~ **PLANT** and associated facilities capable of producing electricity.

Rule 5-1-04 Notice of substantial change

(88) Our April 15 Order adopted certain changes to Rule 5-1-04 relating to the modifications of the definition of "substantial change" in Rule 5-1-01(L). As discussed above, the Commission finds that the existing rule currently in effect more closely tracks the statutory provisions of Section 4935.04(D)(3)(c), Revised Code, than that adopted in the April 15 Order. Therefore, upon reconsideration, the modifications adopted by our April 15 Order are hereby rescinded and no modifications to this rule will be adopted at this time.

Rule 5-5-02 Purpose and scope

(89) AEP objects to new Rule 5-5-02(B) adopted in the April 15 Order which provides:

> 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 website to obtain the current forms before filing a report.

AEP contends that this provision would allow the Commission to make changes to forms which have the effect of changing the content of a Long-Term Forecast Report without going through rulemaking proceedings, without input from the reporting persons, or completing the JCARR process. AEP asserts that if the Commission changes any forms, the reporting persons should be notified of such changes no later than December 31 of each year to allow sufficient time to prepare the report.

The LTFR forms serve as an implementation of the forecast filing rules; they do not go beyond the content or structure defined in the filing rules. To the extent that the forms provide structure for the companies required to file a LTFR, the forms facilitate the filing for the reporting companies. The staff of the Commission has been coordinating this filing activity with the electric utilities for many years and we are not aware of any complaints with respect to either the content of the forms or the timeframes provided in addressing any changes to the structure of the forms. The Commission does not believe that this is a process in need of revision.

Rule 5-5-06 Integrated resource plans for electric utilities

(90) OCEA argues that new Rule 5-5-06(A)(1) should be modified to require a discussion and analysis of any changes that may influence the reporting electric utility's energy and demand forecasts, including demographic and economic changes.

Rule 5-5-06(A)(1) refers to the selection of generating facilities due to technological advances or changes, whereas Section 4935.34(F)(5), Revised Code, referenced by OCEA, refers to the reasonableness of the demand and resource forecasts in relation to population growth estimates. To the extent that non-technological changes such as economic, demographic, or other factors have an influence on the generation mix in the proposed resource plan, Rule 5-5-06(A)(5) requires the electric utility to include such a discussion.

(91) OCEA also contends that Rule 5-5-06(C)(1)(a) should be modified to require the electric utilities to include load duration curves, as well as the system load profile, used to evaluate the mix of resources among base, intermediate, and peaking loads.

We do not believe that load duration curves need to be filed annually in the LTFR, although nothing precludes interested parties from asking for such information during the investigative phase of a forecast proceeding.

(92) OCEA also seeks to revise Rule 5-5-06(C)(1)(b) to require that generation-forced outages and unit availability rates be documented and included as important resource planning information. In addition, OCEA argues that Rule 5-5-06(C)(1)(c) should be modified to require the electric utilities to include the number of units that will be contemplated, and specify the actual machines for multiple unit central station renewable facilities.

In addressing these concerns, we note that unit availability information is included under subsection 5-5-06(C)(1)(c), and that estimates on forced outages for classes of generating units may be found in public sources. We do find that inclusion of the number of units would more accurately reflect the description of the resource plan, and thus we will modify Rule 5-5-06(C)(1)(c) as follows:

> (C) Need for additional electricity resource options.
>
> (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:
>
> ***
>
> (c) NUMBER OF UNITS, UNIT ~~Unit~~ size, and availability of existing and planned units.

(93) OCEA also argues that Rule 5-5-06(C)(1)(d) should be modified to clarify that forecast uncertainty includes uncertainty with respect to the assumptions, such as population, economic conditions, and uncertainty with respect to the relationship between those assumptions and electricity use. Without clarification, OCEA states that the reporting person may provide a limited report addressing only the uncertainties of the electricity used.

We are concerned that OCEA's proposed change would limit, rather than enhance, the electric utility's discussion in its IRP. The forecast uncertainty in this context is a general discussion of the stochastic model assumed to generate the set of forecasts. To the extent that economic, demographic, or other conditions are explicitly modeled into the stochastic model, it is our expectation that the electric utilities will include this discussion. Additionally, there is a specific uncertainty requirement in Rule 5-5-03(D)(1)(d)(ii) that requires the companies to report the size of the standard error of the estimate and the size of the forecasting error associated with each forecasting model equation.

(94) OCEA also suggests that Rule 5-5-06(C)(1)(e) should be modified to clarify and take notice that most thermal plants degrade in performance over their lives, and therefore, any performance forecast should be done based on their remaining useful lives or 20 years, whichever is less. OCEA proposes that the requirement state that the report must include an analysis of the performance over the life of the resource.

We do not believe that the suggested modification is necessary for fulfilling the intent of this rule. While plant performance of thermal units may degrade over the years, such adjustments are generally built into the supply plans over the years as was done in the past. Further, all forms in Rule 5-5-06 that pertain to generation capability require the companies to report on the net demonstrated and net seasonal capabilities of generating units rather than on the name-plate capabilities of generating units.

(95) OCEA contends that Rule 5-5-06(C)(1)(g) should be modified to include buying power as well as selling power. We note that the forms for this rule do require documentation (by year) of the amount of power sold and/or purchased over the 10-year forecast period. This provision will be modified to read as follows:

> Power interchange with other electric systems, including consideration of the ability to BUY AND sell power.

(96) OCEA seeks clarification of the phrase "lost load assessments" in Rule 5-5-06(C)(1)(h). OCEA contends that if the intent is to

require the reporting person to include load shifting or load reduction that decreases margin, the rule should be more specific. OCEA also suggests that Rule 5-5-06(C)(1)(i) should be modified to clarify the information that is expected to comply with the "regulatory climate" factor; and that Rule 5-5-06(C)(1)(j)(i) should require specific information about the utility's reserve margin and loss of load probability.

The Commission has clarified Rule 5-5-06(C)(1)(h) to indicate that the discussion of need should include, first, a description of how price responsive demand and price elasticity due to the implementation of various forms of time differentiated pricing will impact the need for new resources. Time differentiated pricing may include seasonal and time-of-use pricing, as well as real-time, critical peak, peak-time rebate, and other forms of dynamic pricing. Second, plans should include a description of assessments of the value of lost load, providing information on the value to consumers of maintaining additional resources and an additional indication of the prices at which price responsive customers may voluntarily curtail demand.

To the extent that a change in regulation or in environmental compliance, for instance, is eminent, and to the extent that a company decides to incorporate such a change in its resource plan, the rule requires that a discussion be included in the LTFR. We also note that reserve margins will be included on the forms for each of the forecast years. The loss of load probabilities will be conducted regionally by the transmission operators, and the associated results will be published. Accordingly, we find no need to adopt the suggested changes to Rule 5-5-06(C)(1)(j)(i).

(97) With respect to Rule 5-5-06(D)(3), OCEA contends that the Commission should require each electric utility to demonstrate the cost-effectiveness of the IRP through a comparison over a 20-year, rather than a 10-year, forecast horizon of the revenue requirement and to include bill impacts as well as rate impacts of the selected plan and alternative plans evaluated.

We believe the 10-year requirement is sufficient. Previous experience has shown that resource plans for years 11 through 20 are generally highly uncertain and not reliable. The statute requires an updated resource plan on an annual basis to allow for such future adjustments to a resource plan. As for the proposed inclusion of bill impacts, the ingredients of a "bill" are generally more complex than what is required in the context of a forecast proceeding. This rule requires the companies to assess the impact of the proposed and alternative resource plans on their generation rates. The other ingredients of a customer bill, such as distribution and transmission rates, are generally determined in rate cases before this Commission or the Federal Energy Regulatory Commission.

(98) OCEA suggests that Forms FE-R4 and FE-R5 referenced in Rule 5-5-06(E)(4)(a) and (b), respectively, should include actual and projected load duration curves and a resource stack laid over the electric utility's load duration curve.

We do not find these revisions necessary to satisfy the purpose of this rule. Load duration curves and generation resource stacks may be requested under discovery during a forecast proceeding, but we do not believe it necessary for this information to be filed every year in a LTFR.

CONCLUSION:

The Commission finds that, based on the arguments raised by various parties on rehearing, Rules 39-01, 39-05, 39-07, 39-08, 40-01, 40-04, 41-01, 41-03, 5-1-01, 5-1-02, and 5-5-06 adopted by the Commission on April 15, 2009, should be modified as set forth in this Entry on Rehearing. Further, the modifications to Rule 5-1-04 adopted by the Commission on April 15, 2009, are hereby rescinded. The rules to be adopted by this Commission are attached to this entry for filing in this docket but, as in prior rules proceedings, will not be included in the hard-copy distribution of this entry that will be served upon all parties of record. Instead, we find it more prudent and efficient to publish the adopted rules on the Commission's website at www.puco.ohio.gov/puco/rules/ via 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 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 Rules 39-01, 39-05, 39-07, 39-08, 40-01, 40-04, 41-01, 41-03, 5-1-01, 5-1-02, and 5-5-06, as modified herein, are hereby adopted. It is, further, ORDERED, That Rule 5-1-04 not be modified as previously directed in the April 15, 2009 Order. It is, further,

ORDERED, That Chapters 4901:1-39, 4901:1-40, 4901:1-41, 4901:5-1, 4901:5-3 and 4901:5-5, as modified by this Entry on Rehearing, should 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 become effective on the earliest date permitted by law. Unless otherwise ordered by the Commission, the review date for Chapters 4901:1-39, 4901:1-40, 4901:1-41 shall be September 30, 2013. It is, further,

ORDERED, That a copy of this Entry on Rehearing, without the rule attachment, be served upon all parties filing comments in this docket and all interested parties 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/RLH/RRG:geb

Entered in the Journal

JUN 17 2009

Reneé J. Jenkins
Secretary

*** DRAFT – NOT FOR FILING ***

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

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

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

(F) "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.

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

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

(I) "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.

(J) "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

(K) "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.

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

(P) "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.

(Q) "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.

(R) "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.

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

(T) "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.

(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.

*** DRAFT – NOT FOR FILING ***

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:

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

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

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

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

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

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

(D) 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.

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 as set forth in rule 4901:1-39-08 of the Administrative Code, may individually or jointly with the electric utility, apply for exemption from such recovery .

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

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4901:1-39-08 **Commitment for integration by mercantile customers.**

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

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

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

(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 use and peak demand associated with the

customer's projects from the estimated energy use and peak demand that would 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 the 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 savings 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 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 connected to the electricity grid.

(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.

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(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, except for electricity generated by facilities as described in paragraph (E) of rule 4901:1-40-04 of the Administrative Code.

(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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4901:1-40-04 **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.

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

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

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

output that may be quantified and applied toward an advanced energy requirement.

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

(3) Clean coal technology.

(4) Advanced nuclear energy technology, from:

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

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

(5) Energy from a fuel cell.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) Double counting is prohibited.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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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~~ consumption 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.

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

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

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

~~Each~~ Except for electric services companies exempted pursuant to division (A)(1) of section 4928.05 of the Revised Code, 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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4901:5-5-06 **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) Number of units, unit size, and availability of existing and planned units.

(d) Forecast uncertainty.

(e) Electricity resource option uncertainty with respect to cost, availability, commercial in-service dates, and performance.

(f) Lead times for construction or implementation of planned electricity resource options.

(g) Power interchange with other electric systems, including consideration of the ability to buy and sell power.

(h) Price-responsive demand and price elasticity due to the implementation of time-differentiated pricing options and assessments of the value of lost load.

(i) Regulatory climate.

(j) Reliability criteria, including a discussion and analysis of the reporting person's reliability criteria and factors influencing their selection, including, but not limited to:

(i) Reliability measures used and factors including the selection.

(ii) Engineering analysis performed.

(iii) Economic analysis performed.

(iv) Any judgments applied.

(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.

(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.

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(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.

(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."

(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.