

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio)
Edison Company, The Cleveland Electric)
Illuminating Company, and The Toledo)
Edison Company for Authority to Establish) Case No. 08-935-EL-SSO
a Standard Service Offer Pursuant to)
Section 4928.143, Revised Code in the Form)
of an Electric Security Plan.)

OPINION AND ORDER

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The Commission, considering the above-entitled application, hereby issues its opinion and order in this matter.

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OPINION:

I. HISTORY OF PROCEEDINGS

On July 31, 2008, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), and The Toledo Edison Company (TE) (FirstEnergy or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. This application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code. Contemporaneously, in Case No. 08-936-EL-SSO, FirstEnergy filed a separate application for a market rate offer (MRO) in accordance with Section 4928.142, Revised Code.

On August 18, 2008, a technical conference was held regarding FirstEnergy's applications. Subsequently, by entry dated September 5, 2008, the attorney examiner set

this matter for hearing on October 16, 2008. By entry issued September 9, 2008, the Commission scheduled nine local public hearings in this matter.

On August 29, 2008, the Ohio Consumers' Counsel (OCC) filed a motion for bifurcated hearings in Case No. 08-936-EL-SSO, and a motion to consolidate Case No. 08-936-EL-SSO with Case No. 08-935-EL-SSO. On September 8, 2008, FirstEnergy filed a memorandum contra OCC's motions. The city of Cleveland (Cleveland) filed a motion for bifurcated hearings and a memorandum in support of OCC's motion on September 9, 2008. OCC filed a reply to FirstEnergy's memorandum contra on September 11, 2008. The motions to bifurcate the hearings and OCC's motion to consolidate the cases were denied by the attorney examiner on September 12, 2008.

The following parties were granted intervention by entries dated September 15, 2008, and December 16, 2008: Ohio Energy Group (OEG); OCC; Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU-Ohio); Ohio Partners for Affordable Energy (OPAE); Nucor Steel Marion, Inc. (Nucor); Northwest Ohio Aggregation Coalition (NOAC); Constellation NewEnergy and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Ohio Hospital Association (OHA); Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates (Citizens' Coalition); Natural Resources Defense Council (NRDC); Sierra Club; National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); city of Akron; Ohio Manufacturers' Association (OMA); FPL Energy Power Marketing, Inc and Gexa Energy Holdings, LLC (FPL); Cleveland; Northeast Ohio Public Energy Council (NOPEC); Ohio Farm Bureau Federation (OFBF); American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens Power, Inc. (Citizens); Omnisource Corporation (Omnisource); Material Sciences Corporation (Material Sciences); Ohio Schools Council (OSC); Council of Smaller Enterprises (COSE); Morgan Stanley Capital Group; Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (Commercial Group); and Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (OASBO/OSBA/BASA).

The hearing in this proceeding commenced on October 16, 2008, and concluded on October 31, 2008. Eight witnesses testified on behalf of FirstEnergy, 21 witnesses testified on behalf of various intervenors, and nine witnesses testified on behalf of the Staff. At the local public hearings held in this matter 106 witnesses testified. Briefs and reply briefs were filed on November 21, 2008, and December 12, 2008, respectively.

II. DISCUSSION

A. Applicable Law

Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing FirstEnergy's application, the Commission is cognizant of the challenges facing Ohioans and the electric power industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by SB 221.

Section 4928.02, Revised Code, states that it is the policy of the state, inter alia, to:

- (1) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service.
- (2) Ensure the availability of unbundled and comparable retail electric service.
- (3) Ensure diversity of electric supplies and suppliers.
- (4) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management (DSM), time-differentiated pricing, and implementation of advanced metering infrastructure (AMI).
- (5) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality.
- (6) Ensure effective retail competition by avoiding anticompetitive subsidies.
- (7) Ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power.
- (8) Provide a means of giving incentives to technologies that can adapt to potential environmental mandates.

- (9) Encourage implementation of distributed generation across customer classes by reviewing and updating rules governing issues such as interconnection, standby charges, and net metering.
- (10) Protect at-risk populations including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

In addition, SB 221 amended Section 4928.14, Revised Code, which now provides that on January 1, 2009, electric utilities must provide consumers with an SSO, consisting of either an MRO or an ESP. The SSO is to serve as the electric utility's default SSO. The law provides that electric utilities may apply simultaneously for both an MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP. Section 4928.141, Revised Code, specifically provides that an SSO shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the electric utility's rate plan. In the event an SSO is not authorized by January 1, 2009, Section 4928.141, Revised Code, provides that the current rate plan of an electric utility shall continue until an SSO is authorized under either Section 4928.142 or 4928.143, Revised Code.

FirstEnergy's application in this proceeding proposes an ESP, pursuant to Section 4928.143, Revised Code. Paragraph (B) of Section 4928.141, Revised Code, requires the Commission to hold a hearing on an application filed under Section 4928.143, Revised Code, to send notice of the hearing to the electric utility, and to publish notice in a newspaper of general circulation in each county in the electric utility's certified territory.

Section 4928.143, Revised Code, sets out the requirements for an ESP. Under paragraph (B) of Section 4928.143, Revised Code, an ESP must include provisions relating to the supply and pricing of generation service. The plan, according to paragraph (B)(2) of Section 4928.143, Revised Code, may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress (CWIP), an unavoidable surcharge for the cost of certain new generation facilities, conditions or charges relating to customer shopping, automatic increases or decreases, provisions to allow securitization of any phase-in of the SSO price, provisions relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development.

As stated previously, contemporaneous with the filing of this ESP, FirstEnergy filed an application for an MRO. The statute provides that the Commission is required to approve, or modify and approve the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply

under Section 4928.142, Revised Code. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

The Commission may, under Section 4928.144, Revised Code, order any just and reasonable phase-in of any rate or price established under Sections 4928.141, 4928.142, or 4928.143, Revised Code, including carrying charges. If the Commission does provide for a phase-in, it must also provide for the creation of regulatory assets by authorizing the deferral of incurred costs equal to the amount not collected, plus carrying charges on that amount, and shall authorize the deferral's collection through an unavoidable surcharge.

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD (SSO *Rules Case*), the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.06, 4928.14, 4928.17, and 4905.31, Revised Code.

B. Summary of the Local Public Hearings

Nine local public hearings were held in order to allow FirstEnergy's customers the opportunity to express their opinions regarding the issues in this proceedings. The hearings were held in the following cities: September 24, 2008, at 6:30 p.m., Springfield; September 25, 2008, at 12:00 p.m., Cleveland; September 25, 2008, at 6:30 p.m., Cleveland Heights; October 1, 2008, at 6:30 p.m., Sandusky; October 2, 2008, at 12:30 p.m., Toledo; October 2, 2008, at 6:30 p.m., Maumee; October 7, 2008, at 6:30 p.m., Akron; October 14, 2008, at 6:30 p.m., Austintown; and October 15, 2008, at 6:30 p.m., Geneva. At those hearings, public testimony was heard from eight customers in Springfield, 15 customers in Cleveland, five customers in Cleveland Heights, six customers in Sandusky, 20 customers in Toledo, 23 customers in Maumee, nine customers in Akron, 15 customers in Austintown, and five customers in Geneva. In addition to the public testimony, several dozen letters were filed in the case docket by customers stating concern about the application.

The principal concern expressed by customers, both at the public hearings and in letters, was over the increases in customer rates that would result from approval of the application. Witnesses stated that any increase in rates would negatively impact low-income customers, the elderly, and those on fixed incomes. Customers cited the recent downturn in the economy as the primary source of their apprehension. It was noted by many at the hearings that customers are also facing increases in other utility charges, gasoline, food, and medical expenses and that the proposed increase would cause undue hardship. In addition, numerous school officials testified at the local hearings expressing their concerns over FirstEnergy's elimination of the Energy for Education II program effective January 1, 2009.

C. State Policy - Section 4928.02, Revised Code

FirstEnergy maintains that the proposed ESP is consistent with the policy of the state as delineated in Section 4928.02(A) through (N), Revised Code. According to the Companies, the ESP promotes the availability of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service. In addition, the Companies believe that the ESP advances DSM, time-differentiated pricing, advanced metering infrastructure, energy efficiency programs, and the development of performance standards and targets for service quality. Furthermore, FirstEnergy states that the ESP promotes the state's economy and improves the environment. The Companies note that the General Assembly determined that an ESP supports the policies set forth in Section 4928.02, Revised Code, if it is more favorable in the aggregate when compared to the expected results of an MRO (Co. Ex. 1 at 4-5, 7).

OPAE submits that the proposed ESP fails to take into consideration and protect at-risk populations, as required by statute. According to OPAE, the rates proposed in the ESP do not consider the impact of rate increases on low-income households or those struggling to pay their bills (OPAE Br. at 8).

Dominion notes that Section 4928.02, Revised Code, provides that it is the policy of the state to encourage and promote the development of effective retail electric competition. However, Dominion maintains that this policy cannot be effectuated if the SSO price against which the competitive suppliers must compete is based on something other than the cost for the electric utility to provide SSO generation service. While Dominion understands the concern for near-term rate stability, it opines that customers are not well served if costs are deferred for future recovery. Further, Dominion believes that the proposed riders in the ESP, which can produce automatic increases in bills, dispels any illusion that the ESP, as proposed, offers any rate certainty for customers (Dom. Br. at 4-5). OEG contends that the rate increases under the ESP do not consider the state policy to facilitate Ohio's competitiveness in the global economy (OEG Ex. 1 at 16).

FPL states that, although the statute ultimately requires that an ESP be approved if it is more favorable in the aggregate than an MRO, the statute does not permit the approval of an ESP, even one that is more favorable than an MRO, if any component part of the ESP is unreasonable or unlawful. Furthermore, FPL, NOAC, and NOPEC note that the pro-competitive policies enumerated in Sections 4928.143(B) and 4928.20(I) through (K), Revised Code, require that an ESP encourage and promote large-scale governmental aggregation (FPL Br. at 7-8; NOAC/NOPEC Br. at 5). In addition, FPL points out that Section 4928.20(K), Revised Code, requires that the Commission consider the effect on large-scale governmental aggregation of any unavoidable generation charges. FPL maintains that provisions of the ESP that runs afoul of these policies are unreasonable and unlawful, and must be modified or the ESP must not be approved (FPL Br. at 5, 11).

FirstEnergy submits that, contrary to the views of the intervenors, Section 4928.02, Revised Code, does not impose requirements on an ESP and the ESP should not be modified or rejected because it does not satisfy the policies of the state. According to FirstEnergy, the "more favorable in the aggregate" test set forth in Section 4928.143, Revised Code, does not include a reference to the state policies set forth in Section 4928.02, Revised Code, and the Commission has no authority to expand the criteria in Section 4928.142, Revised Code (Co. Reply Br. at 16).

The Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. Therefore, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, the Commission takes into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code. The Commission has reviewed the ESP proposal presented by FirstEnergy, as well as the issues raised by the various intervenors, and we believe that, with the modifications set forth herein, we have appropriately reached a conclusion advancing the public's interest.

D. Application Overview and Term of the Plan

In their application, the Companies are requesting authority to establish an SSO in the form of an ESP pursuant to the provisions of Sections 4928.141 and 4928.143, Revised Code. The proposed ESP is to be effective for a three-year period commencing January 1, 2009, unless the Commission determines, after hearing, that the ESP should be terminated effective January 1, 2011. According to the ESP, if the Commission does not issue a decision terminating the ESP by December 31, 2009, then the ESP could continue through December 31, 2011. If the Commission terminates the ESP effective January 1, 2011, the Companies propose that certain obligations provided for in the ESP would likewise terminate, including the Economic Development Rider (Rider EDR) (Co. Ex. 9a at 1, 32-33; Co. Ex. 5 at 3).

According to the Companies, notwithstanding various adjustments included in the ESP, the overall increases in total customer rates, including generation, transmission, and distribution, would be an average of 5.32 percent in 2009, 4.01 percent in 2010, and 5.9 percent in 2011 (Co. Ex. 9a at 5; Co. Ex. 1 at 12). FirstEnergy notes that the first year increase is attributable to an increase in distribution rates, not generation rates (Co. Br. at 2).

The Companies submit that, upon termination of the generation prices under the ESP, the generation prices will be determined pursuant to a competitive bid process in accordance with an approved MRO process. Likewise, the Companies state that they may

also implement any approved MRO and conduct a competitive bid if the Commission rejects this application for an ESP (Co. Ex. 9a at 34).

With regard to the term of the ESP, IEU-Ohio believes that three years is too short. According to IEU-Ohio, having rate stability only for three years will make it difficult to satisfy the state's policy objectives and for industrial and other customers to make the business case to invest in and maintain their Ohio operations. Further, IEU-Ohio maintains that a longer term plan will provide more tools to help mitigate the significant immediate increases driven by fuel costs (IEU-Ohio Br. at 14).

The Commission believes that FirstEnergy's proposal allowing the Commission to terminate the plan, if the Commission finds it necessary, effective January 1, 2011, is appropriate, in light of the concern about the current state of the economy and the numerous uncertainties facing both the Companies and the consumers in the future. The Commission believes that it is essential that the plan we approve be one that initially requires revenue neutrality for the Companies, provides future revenue certainty for the Companies, and affords rate predictability for the customers. Accordingly, we find that the ESP should be in place for three years, with the option for the Commission to terminate the plan effective January 1, 2011.

E. Base Generation Rates (Rider GEN) and Generation Phase-in Credit (Rider GPI)

In the ESP, the Companies propose a three-year SSO fixed base generation rate (Rider GEN) for customers who choose to receive generation service from the Companies (Co. Ex. 9a at 5; Co. Ex. 5 at 4). However, the Companies propose to phase-in each year's price by means of the Generation Phase-in Credits Rider (Rider GPI), with recovery of the amounts for the phase-in credits over a period not to exceed ten years through the Deferred Generation Rider (Rider DGC) (Co. Ex. 9a at 10, Att. A at 2; Co. Ex. 5 at 8). According to the Companies, this phase-in approach yields a reduction in generation pricing greater than ten percent during the ESP period; thus, mitigating the impact on customers as pricing is transitioned to more closely reflect market pricing. Pursuant to the ESP, the Companies' proposal is as follows:

	Proposed Generation Price (Rider GEN)	Average Price per kWh	Base kWh	Proposed Phase-in Price per kWh (Rider GPI)
2009	\$0.075			\$0.0675
2010	\$0.080			\$0.0715
2011	\$0.085			\$0.0755

The Companies further explain that the generation charges and phase-in credits will be seasonally and voltage adjusted for all three years in the retail tariffs (Co. Ex. 9a at 10; Co. Ex. 5 at 7-9).

According to the Companies, on average, their proposal would represent an increase in the customer's total bill of 0.06 percent in 2009, 4.01 percent in 2010, and 5.79 percent in 2011 (Co. Ex. 9a at 5). Kroger recommends that the ESP be modified to ensure that the overall increase attributable to increased generation charges be as close to these levels cited by the Companies as possible (Kroger Ex. 1 at 8).

OCC states, and Material Sciences agrees, that the generation rates proposed by the Companies in the ESP are excessive and, if a more appropriate rate is developed, then Rider GPI would not be necessary (OCC Ex. 3 at 36; Mat. Sci. Br. at 13). OHA states that the proposed generation rates are arbitrary and unreasonable (OHA Br. at 9). The Competitive Suppliers¹ aver that FirstEnergy is not really discounting the cost of generation through Rider GPI, only delaying the collection with carrying costs, which has the effect of increasing the total cost of generation which customers have to pay (Comp. Supp. Br. at 17). IEU-Ohio states that, while Section 4828.144, Revised Code, permits the phase-in of rates, it limits the resulting surcharges that amortize the cost of the phase-in such that they must apply during the term of the ESP. However, IEU-Ohio points out that the deferral aspects of the ESP have an impact beyond the three-year term of the ESP (IEU-Ohio Br. at 13).

FPL, which has executed a letter of intent to provide electric supply to NOPEC during the term of the ESP (FPL Br. at 1), argues that the ESP contains numerous anticompetitive provisions that would prevent competitive suppliers from entering the market and FPL from serving NOPEC's customers. For example, FPL states that the net pricing disadvantage to competitive suppliers if Rider GPI and the Minimum Default Service Rider (Rider MDS) are approved is 26 percent (FPL Ex. 1 at 10-11, 15; FPL Br. at 3). According to FPL, because of the onerous effect of Riders GPI and MDS, the NOPEC letter of intent contains two conditions precedent to FPL's execution of the agreement, namely, the approved ESP must extend the full amount of any Rider GPI to large-scale governmental aggregations and Rider MDS must be made avoidable for large-scale governmental aggregations (FPL Br. at 4).

FPL advocates that Rider GPI, as proposed in the ESP, violates the legislative mandate to encourage and promote large-scale governmental aggregation and, therefore, it must be modified (FPL Br. at 5). NOAC and NOPEC argue that Rider GPI and the deferral it accomplishes create a barrier to competition and a subsidy from one group of consumers to another. NOAC and NOPEC point out that Rider GPI applies only to

¹ Constellation and Integrys submitted joint exhibits and filed a joint initial brief; therefore, when referring to the arguments in these documents, these parties will be referred to as the Competitive Suppliers.

consumers who accept Rider GEN from the Companies. In order to provide savings to a consumer, a large-scale governmental aggregator would need to be able to purchase generation at a price lower than Rider GEN less the ten percent Rider GPI credit; thus, Rider GPI is a significant barrier to competition. NOAC and NOPEC recommend that the ESP be modified to provide a governmental aggregation generation credit that would be made available to customers served by a large-scale governmental aggregation that is equivalent to Rider GPI. Further, they offer that the generation costs deferred through both Rider GPI and the governmental aggregation credit should be included in Rider DGC beginning in 2011 (NOAC/NOPEC Jt. Ex. 1 at 6, 8-9). FPL supports this proposal by NOAC and NOPEC (FPL Ex. 1 at 10-11, 15). The Competitive Suppliers agree that the playing field can be leveled if FirstEnergy gives each shopping customer a credit equal to the generation deferral (Comp. Supp. Ex. 1 at 14). The Consumer Advocates believe that alternative treatment for generation deferrals, which would deal with the anticompetitive effects of the proposed deferrals, should remain a secondary consideration and that the primary goal should be the elimination of the deferrals (Con. Adv. Br.² at 20).

In response to the criticisms of the phase-in and the deferrals proposed in the ESP, FirstEnergy points out that Section 4928.144, Revised Code, expressly authorized the phase-in of generation prices, along with other deferrals. In addition, FirstEnergy notes that, with the exception of governmental aggregation programs as set forth in Section 4928.20(I), Revised Code, Section 4928.144, Revised Code, also directs that the deferrals plus carrying charges be collected through an unavoidable surcharge on rates of an electric distribution utility (Co. Br. at 33).

Staff notes that Section 4928.63(C)(3), Revised Code, provides that electric utilities may be excused from complying with the annual alternative energy portfolio standards if their annual compliance exceeds a certain level. Staff believes that the reduction of the base generation prices through the use of deferrals could potentially impact the implementation of this statutory provision. Therefore, Staff recommends that the Commission reinforce that no part of any deferred generation-related amounts should include alternative energy portfolio standard related compliance costs (Staff Ex. 1 at 4-5; Staff Br. at 18).

With regard to Rider GEN and the proposed base generation rates, the Commission notes that, at the hearing, FirstEnergy's witness Warvell acknowledged that the generation rates proposed by FirstEnergy were not based upon cost, but were based solely on the judgment of FirstEnergy's management (Tr. I at 64, 167-168). Mr. Warvell testified that it is FirstEnergy's understanding that the two objectives for an ESP are for the rates to be below the rate which could be obtained through an MRO and for rates to be stabilized (Tr. I at 26, 48). Further, FirstEnergy presented testimony at the hearing indicating that the

² OCC, Cleveland, NRDC, NOAC, and Citizens Coalition filed a joint initial brief; therefore, when referring to the arguments in this document these parties will be referred to as the Consumer Advocates.

generation rates proposed by FirstEnergy are below the rates which could be obtained through an MRO (Co. Ex. 1 at 18, Att. 1 at 1). However, this testimony was based upon the market information available to FirstEnergy on July 15, 2008, immediately prior to the filing of its application on July 31, 2008 (Tr. I at 102-103; Tr. III at 13).

The record in this proceeding demonstrates that, after the filing of the application by FirstEnergy, there was a significant decline in prices in the relevant energy markets (Tr. I at 99-103, 184-184). FirstEnergy's witness Jones acknowledged a decline in energy prices between July 15, 2008, and the date of the hearing, but he stated that he had not calculated the impact of that decline in his testimony (Tr. III at 85). Because the decline occurred after the filing of the application by FirstEnergy, this decline was not reflected in the prices proposed by FirstEnergy. Therefore, if the Commission is to accept the two objectives for the ESP proposed by FirstEnergy, that the rates for the ESP should be below the prices which could be obtained through an MRO and that rates should be stabilized, it is necessary to reduce the average base generation rates contained in FirstEnergy's application.

The Commission finds that the record supports a reduction in the proposed base generation rates of approximately 10 percent for 2009, with additional reductions thereafter, in order to reflect the market decline between the date of the filing of the application and the hearing. A comparison of the forward prices used by OEG witness Kollen, using October 10, 2008, market data, with forward prices used by FirstEnergy's witness Jones using July 15, 2008, market data, indicates a decline of approximately 12 percent (OEG Ex. 2-A, Exhibit LK-8A; Co. Ex. 6, Exhibits 8-10). As previously noted, FirstEnergy's witness Jones testified that he had not calculated the impact of the market decline (Tr. 111 at 85). Moreover, OCC's witness Yankel testified that prices had declined by approximately 10 percent (OCC Ex. 3 at 5; OCC Ex. 8; OCC Ex. 9; OCC Ex. 10; Tr. VI at 182-185). Further, Kroger's witness Higgins recommended that the Commission reduce the base generation rates to \$0.0675 per kWh for 2009; this recommendation would reduce base generation rates by approximately 10 percent (Kroger Ex. 1 at 3, 8). Therefore, the Commission concludes that it is appropriate to reduce the average base generation rates proposed in FirstEnergy's application to \$0.0675 per kWh for 2009, \$0.0695 per kWh for 2010, and \$0.071 per kWh in 2011. Accordingly, the Commission finds that FirstEnergy's proposed ESP should be modified in order to reflect these reductions.

Turning now to Rider GPI, the Commission acknowledges that Section 4928.144, Revised Code, authorizes the Commission to order an electric utility to phase-in any rate established under Section 4928.143, Revised Code, in order to ensure rate stability to customers. FirstEnergy has proposed a generation phase-in credit under which the Companies would defer a portion of the base generation costs and recover these deferrals, with carrying costs, through Rider DGC. In its application, FirstEnergy proposed a generation phase-in credit in the amount of \$0.0075 per kWh for 2009, \$0.0085 per kWh for

2010, and \$0.0095 per kWh for 2011. The Commission believes that, with the modifications to the average base generation rates, no such deferrals would be necessary. The Commission notes that the aggregate cost of the deferrals, including carrying costs, proposed by FirstEnergy amounts to nearly \$2 billion, which would need to be recovered from ratepayers in the future (Co. Ex. 9a, Att. A; Co. Ex. 5 at 8; Tr. 11 at 280-282). Although there would be short-term benefits to such a deferral in the form of lower billed generation rates, the need for recovery of nearly \$2 billion in deferred generation rates and carrying costs has the potential to damage Ohio's competitiveness in the global economy over the long-term as new businesses may be deterred from locating in Ohio in the future. Accordingly, the Commission finds that Rider GPI should be eliminated from the ESP.

Moreover, the Commission is mindful of the significant economic difficulties facing residents in Ohio at this time, as reflected in the record of the nine local public hearings held in this proceeding. Thus, we note that the average base generation rate for 2009, as approved in this order, represents no increase in electric rates for residential customers served by the Companies.

1. Generation Procurement

According to the Companies, integral to the ESP is an arrangement with FirstEnergy Solutions (FES) for generation supply. Under this arrangement, the Companies explain that there would be additional benefits to customers. Among these benefits would be an addition of 1,000 megawatts (MW) of capacity through either new or upgraded generation, maintaining generation in service that would otherwise be shutdown, and/or additional generation. Furthermore, the Companies state that FES will commit up to \$45 million over the term of the plan toward environmental remediation and reclamation (Co. Ex. 9a at 7, 17).

OEG contends that the generation rate proposed in the ESP is not reasonable, stating that FirstEnergy has failed to show that the prices for purchased power from FES are prudent (OEG Ex. 2 at 19; Tr. I at 26). In addition, OEG alleges that the proposed rates are not consistent with the policy of the state set forth in Section 4928.02, Revised Code (OEG Br. at 14). OEG further states that the base generation rates proposed in the ESP are in excess of the market prices; stating that, based on September 19, 2008, forward prices, the wholesale market price to serve the Companies' load would be \$63.45, \$65.23, and \$66.15 per MWh, for 2009, 2010, and 2011 respectively; compared to FES's offer price proposed in the ESP of \$75, \$80, and \$85 per MWh, respectively, for the same years (OEG Ex. 2 at 4, 11, 19). OPAE agrees that the lack of transparency concerning the contractual terms with FES and the lack of justification for the proposed generation prices are fatal flaws in the ESP (OPAE Ex. 1 at 15). In addition, OCC asserts that the forecasted rates developed by the Companies to determine the market price benchmarks for generation are highly inflated; thus, giving a false impression of the value of the rates being proposed in the ESP. Based on data from July 15, 2008, and taking in consideration adjustments for

load shaping and distribution losses, OCC calculates that the more realistic forward market prices would be \$55.65, \$54.78, and \$53.87 per MWh for 2009, 2010, and 2011, respectively (OCC Ex. 3 at 12; Con. Adv. Br. at 12).

OEG recommends an active portfolio as an alternative, whereby the Companies would issue requests for proposal for all facets of wholesale generation supply sufficient to meet their provider of last resort (POLR) requirements. OEG proposes that these purchases should only be made at transparent and verifiable Federal Energy Regulatory Commission (FERC) regulated wholesale market rates. According to OEG, the goal would be to obtain the least cost portfolio of wholesale generating resources, which would include a mix of fixed block wholesale contracts, spot purchases, and sales contracts, to supply those customers who do not shop. OEG also states that the Companies should retain the POLR responsibility, rather than outsourcing it to the wholesale generation suppliers. To the extent costs are prudently incurred, OEG states that the Companies should be permitted to recover all of their competitively bid generation supply cost, including the costs for the risk. OEG believes that this method will significantly reduce the cost of wholesale generation (OEG Ex. 1 at 8-11; OEG Ex. 2 at 14, 17, 21). OHA supports OEG's proposed procurement process (OHA Br. at 12).

OPAE proposes that FirstEnergy be required to evaluate options to assure generation supply to its customer classes. OPAE believes that the analysis should start with an examination of the Companies' current and future load and load shapes for each customer class. OPAE advocates that the Companies should then evaluate how they can manage this load shape and meet their needs under a variety of potential scenarios that would evaluate the cost of effective energy efficiency and demand response products compared to purchasing traditional generation supply at the lowest price (OPAE Ex. 1 at 16-17).

OCC and OPAE recommend that FirstEnergy's proposed cost recovery for new generation sources, including the contract with FES for an additional 1,000 MW, or for long-term power purchase contracts identified in the ESP not be approved, because of the lack of resource planning information provided by FirstEnergy in its application. OCC and OPAE agree that approval should depend on the Companies' demonstration that such resources are least-cost as determined in a formal long-term forecast and integrated resource planning process (OCC Ex. 1 at 20; OPAE Ex. 1 at 18).

In light of the Commission's determination in this order that the average base generation rates proposed by the Companies must be reduced to an appropriate level, as well as other modifications to the ESP set forth in this order, we find that the issues raised by several of the intervenors regarding the FirstEnergy's proposed procurement of generation from FES have been taken into consideration and addressed. As for FES's commitments to provide 1,000 MW of capacity and to provide \$45 million toward

environmental remediation and reclamation, the Commission agrees with OCC and OPAE that these commitments should be eliminated (OCC Ex. 1 at 20; OPAE Ex. 1 at 18).

2. Section 199 Tax Deduction

IEU-Ohio points out that, pursuant to Section 199 of the Internal Revenue Service Code, a deduction against federal taxable income is available for qualified production activities income, which includes the production of electricity. IEU-Ohio states that the Companies have not reflected the Section 199 tax benefits in the base generation prices proposed in the ESP. According to IEU-Ohio, to the extent that the Section 199 deduction associated with the generation supplied by FES to the Companies can be utilized in FirstEnergy's consolidated tax return, it is appropriate for that tax benefit to be reflected in the generation rates. IEU-Ohio argues that, if the Companies are not able to demonstrate that the price of generation is net of Section 199 tax benefits, they should not be allowed to pass along the costs of new taxes associated with generation (IEU-Ohio Ex. 1 at 5-7).

The Commission acknowledges that, as pointed out by IEU-Ohio, the generation supplied by FES to the Companies may qualify for the Section 199 deduction. In previous cases, the Commission has recognized the possibility of the applicability of this deduction and has required other electric utilities to make adjustments reflecting this deduction. See *Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC (October 3, 2007). Thus, the Commission agrees that applicable Section 199 deductions should be taken into consideration. That being said, we believe that the modifications set forth in this order adequately account for the possibility of any applicable Section 199 tax deductions.

3. Generation Rate Design

Under the ESP, generation charges, which are seasonally and voltage adjusted, are levied on all customer classes on a per kilowatt hour (kWh) basis. According to FirstEnergy, there are two main considerations that form the basis for the proposed generation rate design in the ESP. First, the ESP proposal uses the rate classifications developed by the Companies in Case Co. 07-551-EL-AIR (*FirstEnergy Distribution Rate Case*). Second, according to the Companies, the proposed rate design incorporates the concept of gradualism in the transition from historic rate levels and structures to the proposed rate classifications and components of the ESP in order to mitigate customer impacts. FirstEnergy explains that the base distribution rates in the ESP utilize the Companies' updated filing in the *FirstEnergy Distribution Rate Case*; however, the ESP proposal incorporates the following changes to that update: (1) a single rate block structure for residential customers; (2) the revenue distribution and the rate design set forth in the stipulation and recommendation filed in the *FirstEnergy Distribution Rate Case* on February 11, 2008; (3) tariffs that produce the distribution increase pursuant to the terms of the ESP; (4) removal of the DSM Rider and incorporating the same charge in

Demand Side Management and Energy Efficiency Rider (Rider DSE); and (5) to be consistent with the riders proposed in the ESP, the seasonal price change in the billing and payment section of the electric service regulations was modified (Co. Ex. 4 at 5-6).

Staff states that the Companies' proposed voltage-based rate design is reasonable (Staff Ex. 5 at 4). The Commercial Group supports the Companies' proposal for seasonal and voltage level adjustments to its generation cost, as well as the optional time-of-day differentiated generation service price option. However, the Commercial Group states that the Companies should investigate whether a pricing option based on the functional cost of generation, i.e., capacity and energy pricing elements, would provide more accurate price signals (Com. Gr. Ex. 1 at 7). Nucor also recommends that the time-of-day proposal be modified to include two separate pricing periods; for example, peak and shoulder pricing periods (Nucor Ex. 3 at 30).

IEU-Ohio argues that the proposed per kWh rate design is not appropriate for large customers because it provides no price signal that the customer's load factor contributes to the cost of providing electricity (IEU-Ohio Ex. 1 at 9). Kroger agrees that the elimination of any rate differentiation based on load factor causes substantial negative impacts on higher-load factor, non-residential customers (Kroger Ex. 1 at 9). IEU-Ohio believes that the elimination of the demand charge would change the customer's load shape and increase the customer's peak demand (Tr. VIII at 86; IEU-Ohio Br. at 31). According to IEU-Ohio, not only does the load factor affect variable costs, but a higher load factor means that the fixed costs are spread over a greater quantity of usage, thus lowering the overall average costs per kWh. IEU-Ohio alleges that designing generation charges to be entirely kWh based implicitly suggests that such costs are entirely variable, which IEU-Ohio does not accept; however, if the generation costs are entirely variable, IEU-Ohio opines that there is no need for shopping customers to pay for default or standby service (IEU-Ohio Ex. 1 at 9-10). The Companies disagree that the removal of the demand charges from retail rates will cause a change in customers' load profiles (Co. Ex. 20 at 18).

IEU-Ohio recommends that, once the generation revenue requirement has been established for the transmission, sub-transmission, and primary rate schedules, the generation rider should be structured as a two-part rate consisting of both demand and energy components. Since there is no cost-of-service study, IEU-Ohio recommends a demand charge of \$14 per kW and that the remainder of the revenue requirement be collected through seasonally differentiated kWh charges (IEU-Ohio Ex. 1 at 10; IEU-Ohio Br. at 30). IEU-Ohio also proposes that partial service and cogeneration schedules should be included as part of the ESP. IEU-Ohio points out that cogeneration is one option that can be used to fulfill the alternative energy resource portfolio obligations in SB 221 (IEU-Ohio Ex. 1 at 13).

OEG maintains that the ESP rate proposals fail to adequately mitigate the increase to large industrial customers. According to OEG, the increases for the Companies' largest industrial manufacturing firms range from 25 percent to 34 percent, compared to the retail average increases in the five percent range for the other customer classes (OEG Ex. 1 at 16-20). OEG recommends that the increases proposed under the ESP be modified using the following rate mitigation plan principles: residential rates should reflect the increases and not be charged any costs for rate mitigation or, if alternative wholesale generation rates are approved, residential rates should be adjusted with the residential class sharing the costs; no rate schedule should receive an increase greater than two times the average increase; and no rate schedule should receive a rate decrease if other schedules get an increase. OEG recommends its mitigation plan be accomplished via the charges and credits contained in the Companies' Rider EDR. According to OEG, its mitigation plan: moderates the full effect of wholesale cost increase to the industrial class by increasing Rider EDR on non-residential customers; provides incentives to industrial customers to remain on the SSO; and benefits all non-shopping customers by minimizing the retail risk premium that must be added to the wholesale generation price (OEG Ex. 1 at 20-24). Nucor supports OEG's rate mitigation proposal (Nucor Br. at 20). OSC points out that the effect of applying OEG mitigation plan principles to the eight rate schedules proposed by the Companies would be to further increase the rates confronting schools under the ESP (OSC Reply Br. at 5).

Nucor further advocates that, regardless of whether the ESP is a cost-of-service proposal or a market-based proposal, the rates between the classes should reflect cost-of-service differentials (Nucor Br. at 17). Nucor argues that large industrial customers under transmission rate schedules and most lighting customers will get significant rate increases. Nucor offers that transmission customers will receive increases of between 14 and 34 percent, and, for some transmission customers served under interruptible rates, like Nucor, the increase will approach or exceed 50 percent. Nucor does not believe that such charges are cost-based; rather, such disparate increases for high-load factor transmission customers and off-peak lighting classes are attributable to the fact that FirstEnergy has not properly reflected the cost of generation capacity in the rates for customer classes. According to Nucor, with the exception of voltage differentials, the ESP generation rates do not recognize cost differences to serve specific classes, e.g., loads characterized by timing, duration, and load factor. Nucor and Kroger agree that the time-of-use price differentials in the ESP do not address class-specific cost differences (Nucor Ex. 3 at 9-11; Kroger Ex. 1 at 11). Nucor alleges that the result is generation rates that create interclass subsidies and large rate increases for selected classes (Nucor Ex. 3 at 11). Nucor recommends that the generation rates be modified to reflect the class-specific cost differences and that FirstEnergy develop class allocation factors which would first be adjusted to the proposed uniform generation rate, followed by the time-of-use, and voltage adjustments (Nucor Ex. 3 at 14-15). Kroger recommends that, for rate schedules for high-load factor customers, the existing generation-related rate components should be

amalgamated into a single base generation charge, and then a rate schedule specific rider should be applied to this base charge to recover the requisite change in generation revenue authorized in the ESP (Kroger Ex. 1 at 11-12). Nucor advocates that, if its class allocation factor proposal is not adopted, then FirstEnergy should be required to retain all existing rates and to apply an across-the-board generation increase to FirstEnergy's existing rates (Nucor Br. at 21).

The Commercial Group offers that the Companies' generation cost deferrals and Rider GPI should also track costs based on customer class (voltage level), season, and time-of-day period costs (Com. Gr. Ex. 1 at 7). OHA states that the rate design should be reflective of the manner in which costs are incurred, on a reserved capacity basis (OHA Br. at 18).

OCC disagrees with the proposal in the ESP that eliminates the demand components for non-residential customers. OCC maintains that demand components in generation rates for large customers reduce the bid price. Further, OCC suggests that elimination of demand charges from non-residential generation tariffs will encourage an inefficient demand for, and use of, generation resources. OCC submits that the Companies' interruptible load response programs (Economic Load Response Program [Rider ELR] and Optional Load Response Program [Rider OLR]) and the seasonality factors do not provide enough control over the growth demand (OCC Ex. 1 at 22-24). Further, OCC states that, until the Companies can provide justification why an inverted rate block structure is appropriate for residential customers, residential customers under Rider 88 should be given a flat-rate (OCC Ex. 3 at 32).

NRDC states that there are good public policy reasons for ensuring that the Companies are made whole for the revenue they forgo as a result of energy efficiency programs; however, the Companies' lost revenue adjustment proposed in the ESP does nothing to remove the Companies' incentive to increase kWh sales. NRDC submits that the disincentive toward energy efficiency could be removed if revenue decoupling is adopted in FirstEnergy's service territory (NRDC Ex. 1 at 10-11).

It is the Commission's understanding that the Companies are requesting that the rate design and tariff structure developed by the Companies in the *FirstEnergy Distribution Rate Case* also be adopted in this case for the generation service. However, the Commission will not be determining the substantive issues of the *FirstEnergy Distribution Rate Case* in this case. Moreover, based upon the issues raised by the intervenors in this proceeding, the Commission finds that FirstEnergy has not demonstrated that the proposed rate design and tariff structure properly allocates the cost of providing generation service to the appropriate customers. Therefore, we decline to implement a new generation rate design and tariff structure at this time. Instead, the Commission finds that FirstEnergy should file new tariffs adjusting its current rate design and tariff structure

to implement the new base generation rates approved by the Commission in the ESP. These proposed tariffs should maintain the current rate relationships between customer classes and among the rate schedules within each customer class.

In addition, the Commission agrees that the issues raised by various intervenors regarding the inclusion of demand components in the generation rate design must be addressed. To that end, the Commission finds that FirstEnergy should work with Staff, and other stakeholders, to develop a means of transitioning FirstEnergy's generation rate schedules to a more appropriate rate structure which takes into consideration of time-varying generation costs of serving different customers and classifications of customers with homogenous loads and/or generation cost profiles, considers customer load factor, incorporates seasonal generation cost differentials, and, where adequate metering is available, provides customers with time-differentiated and dynamic pricing options. Further, as part of our approval of this ESP, the Commission will modify the ESP to authorize FirstEnergy to make periodic, revenue-neutral, Rider GEN tariff filings, subject to Commission review and approval, to implement a revised new rate design on a gradual basis consistent with its collaborative effort with Staff. Accordingly, the ESP, as proposed, should be modified consistent with our determination herein.

F. Generation Riders and Programs

1. Deferred Generation Cost (Rider DGC)

As stated previously, the Companies propose that approximately ten percent of the generation price during the three-year ESP period be deferred, with carrying charges, and recovered in the future through Rider DGC. Rider DGC would be an unavoidable rider for all customers, with the exception of certain governmental aggregation customers, consistent with Section 4928.20(I), Revised Code (Co. Ex. 9a at 5, 11; Co. Ex. 5 at 9). The Companies estimated that, in the aggregate, the deferred amounts would be \$430 million in 2009, \$490 million in 2010, and \$550 million in 2011 (Co. Ex. 9a, Att. A; Co. Ex. 5 at 8). The Companies set forth two options for the recovery of the deferred costs in Rider DGC (Co. Ex. 9a, Att. A at 2).

The first option assumes no securitization and would allow the Companies to begin recovering the costs and carrying costs deferred pursuant to the generation rate increase phase-in effective with services rendered on and after January 1, 2011, through implementation of Rider DGC averaging \$0.002009 per kWh. It is projected that, under the first option, Rider DGC would increase in 2013 and decrease in 2021. Pursuant to option one, Rider DGC would be reconciled semiannually and it would not continue beyond December 31, 2022 (Co. Ex. 9a at 11-13, Att. A at 2-3; Co. Ex. 2 at 12).

The second option would allow the Companies, with the Commission's approval, to securitize, at least on an annual basis, the accumulated balance of the deferred

generation charges, together with the associated carrying charges and the related securitization transaction costs, effective with services rendered on and after January 1, 2010, through implementation of Rider DGC averaging \$0.000893 per kWh. The Companies explain that, in accordance with this option, each year's generation phase-in costs may be securitized in separate transactions, as authorized by Sections 4928.143(B)(2)(f) and 4928.144, Revised Code, by issuing bonds with scheduled final maturities not to exceed ten years. It is projected that, under the second option, Rider DGC would increase in 2011 and 2012, and decrease in 2020 and 2021. Pursuant to option two, Rider DGC would be reconciled semiannually, as well as on a non-routine basis, and it would not continue beyond December 31, 2021 (Co. Ex. 9a at 11-14, Att. A at 3-9; Co. Ex. 2 at 13; Co. Ex. 1 at 25).

The Commercial Group states that, whichever deferral mechanism is employed, it should provide full recovery of the deferrals to the Companies, but at the lowest possible cost to retail customers. Therefore, if the first option, without securitization, is adopted, the Commercial Group recommends that the carrying charge include all deferred tax offsets associated with unrecovered generation prices and carry net of tax balance at the Companies' cost of long-term debt. If the second securitization option is adopted, the Commercial Group recommends a special securitization proceeding be held to consider the economic benefits of the use of such bonds (Com. Gr. Ex. 1 at 8).

Dominion submits that all riders designed to recover generation-related costs, such as Rider DGC, must be made avoidable for shopping customers if there is to be any hope for retail competition (Dom. Br. at 6). Similarly, the Competitive Suppliers state that this rider should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for costs properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 8-9 and Ex. 3 at 8). In addition, the Competitive Suppliers state that this deferral masks the true cost of the ESP generation and artificially suppresses conservation by reducing the value of using less electricity (Comp. Supp. Br. at 16).

Staff, OHA, and Kroger are opposed to the generation deferrals requested by the Companies (Staff Ex. 6 at 3; OHA Br. at 15; Kroger Ex. 1 at 8). Kroger does not favor a program in which customers accumulate a very substantial debt owed, with interest, to FirstEnergy (Kroger Ex. 1 at 8). Staff believes deferrals present too many difficulties and distortions. While Staff notes that it is not opposed to smoothing out the rate shock problem, Staff does not recommend a process which extends the collection through an unavoidable charge beyond the ESP period (Staff Ex. 6 at 3). Rather than deferrals, Staff recommends that a rate structure coupled with a reconciliation adjustment will generate sufficient revenues for FirstEnergy to recover the costs of providing an SSO, while at the same time earning a fair return on its investment. Staff offers that, through an annual or semi-annual true-up mechanism, generation rates could be adjusted either up or down,

but no higher than the generation rates proposed by the Companies, to reflect the actual cost of power acquisition (Staff Br. at 8-10). FPL states that, while rejection of Rider GPI would satisfy its interest, so would the development of a levelized SSO as proposed by Staff, therefore, FPL supports Staff's proposal (FPL Br. at 16).

NOAC and NOPEC aver that Section 4928.20(I), Revised Code, provides that large-scale governmental aggregation participants only pay the portion of Rider DGC that represents the benefits the participants received; however, the ESP does not say that. Therefore, NOAC and NOPEC state that the ESP lacks any detail on how this statutory requirement will be implemented and this uncertainty is an impediment to large-scale governmental aggregation. However, NOAC and NOPEC point out that the initial barrier of Rider GPI makes it unlikely that a governmental aggregator would secure power supplies at a low enough price to provide the opportunity for avoidance of Rider DGC (NOAC/NOPEC Jt. Ex. 1 at 7-8).

As stated previously, the Commission has determined that there should be no deferral of generation rates as proposed by FirstEnergy. Therefore, there is no need for Rider DGC. Accordingly, FirstEnergy's ESP should be modified to eliminate this rider. Elimination of this rider will save customers, in the long-term, approximately \$500 million in carrying costs (Tr. 11 at 280, 282). The Commission believes that this savings will help promote, in the long-term, the competitiveness of Ohio in the global economy.

2. Capacity Cost Adjustment (Rider CCA)

Pursuant to the ESP, the Capacity Cost Adjustment Rider (Rider CCA) would be an avoidable rider that would account for the capacity purchases made by FES which are required to meet the applicable standards of FERC, North American Electric Reliability Corporation (NERC), Midwest Independent Transmission System Operator, Inc. (MISO), or others for planning reserve margin requirements for the Companies' retail load. Purchases made for the period May 1 through September 30 of each calendar year of the plan would be recoverable through Rider CCA. Furthermore, in accordance with the ESP, the Commission may elect to increase the generation rate phase-in amounts, to the extent of any charges for planning reserves under Rider CCA, but only to the extent such charges exceed 1.5 percent of the then existing average annual total rates of the Companies (Co. Ex. 9a at 18; Co. Ex. 5 at 12-13).

OEG states that it is not opposed to Rider CCA to the extent it applies to firm POLR load. However, OEG argues that it is the responsibility of FirstEnergy to obtain sufficient annual planning reserves, based on their firm load, not interruptible load. OEG submits, and Nucor agrees, that it is inappropriate to charge Rider CCA to interruptible load (OEG Ex. 1 at 32; Nucor Br. at 54).

As noted previously, OCC recommends that demand components for non-residential customers be part of the ESP. However, if such components are not part of the ESP, OCC recommends that Rider CCA be rejected and that the Companies bear the risk of their rate design in the event that capacity is insufficient (OCC Ex. 1 at 24; OCC Ex. 3 at 37).

FPL advocates that Rider CCA, as proposed in the ESP, violates the legislative mandate to encourage and promote large-scale governmental aggregation and, therefore, it must be modified (FPL Br. at 5). FPL states that the ESP fails to provide transparency on how FirstEnergy will determine its capacity charges. Therefore, FPL believes that, in order to ensure a level playing field for competitive suppliers, FES should procure capacity in the market needed to meet the planning reserve requirements for all customers for the entire term of the ESP and that associated costs should be recovered through an unavoidable rider (FPL Ex. 1 at 17). In the alternative, FPL recommends that FirstEnergy provide an estimate of the MISO designated network resource capacity it plans to make available to meet planning reserve requirements and a reasonable forecast of Rider CCA, in order to provide pricing transparency (FPL Br. at 29). In response, FirstEnergy states that the process contemplated for Rider CCA does provide transparency in that the cost estimates and actual costs incurred will be reviewed and approved by the Commission (Co. Reply Br. at 51).

The Commission understands that Rider CCA, as proposed by the Companies, is an avoidable rider and that the purpose of this rider is to account for capacity purchases during the summer months in order to meet applicable planning reserve margin requirements. The availability to consumers of adequate, reliable, safe, and efficient electric service is one of the cornerstones of the state electric policy set forth in Section 4928.02, Revised Code. In balancing these important needs of consumers with the issues raised by several of the intervenors, the Commission believes that Rider CCA is a reasonable mechanism that will advance the state policy. However, the evidence in the record demonstrates that FirstEnergy is required to obtain sufficient annual planning reserves based upon their firm load and not their interruptible load (OEG Ex. 1 at 32; Tr. II at 33-34, 40-41). Therefore, the Commission agrees that FirstEnergy should not be permitted to charge customers Rider CCA for their interruptible load and that Rider CCA should be modified to apply only to firm load. Accordingly, the Commission finds that Rider CCA should be approved, as an avoidable rider and it should not be charged to FirstEnergy's interruptible customers.

3. Minimum Default Service Rider (Rider MDS)

Pursuant to the ESP, Rider MDS would be an unavoidable rider that would compensate the Companies for the administrative costs and hedging costs associated with committing to obtain adequate generation resources to supply the entire retail customer load, recognizing the risk and costs of customers switching to an alternative generation

supplier. The Companies propose that Rider MDS be equal to 1.0 cent per kWh (Co. Ex. 9a at 14; Co. Ex. 5 at 10-11). According to the Companies, Rider MDS is permitted by Section 4928.143(B)(2)(d), Revised Code. The Companies explain that the minimum default service charge is included in the base generation charge in Rider GEN for non-shopping customers and separately charged to shopping customers through Rider MDS; however, the minimum default service charge is not subject to the generation phase-in deferral referenced above for the base generation charge (Co. Ex. 9a at 10, 14; Co. Ex. 5 at 8). According to FirstEnergy, without this unavoidable charge, the base generation charges in the ESP would need to be increased (Co. Ex. 5 at 12).

The Competitive Suppliers state, and Dominion agrees, that Rider MDS should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for cost properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 8-9 and Ex. 3 at 8; Dom. Br. at 6).

IEU-Ohio, Nucor, NOAC, NOPEC, OCC, Cleveland, OHA, and FPL argue that Rider MDS is not reasonable or appropriate, and that the Companies have not provided cost support for this level of charges (IEU-Ohio Ex. 1 at 7; Nucor Ex. 3 at 31; NOAC/NOPEC Jt. Ex. 1 at 12-13; OCC Ex. 3 at 34; Cleve. Ex. 1 at 4; OHA Br. at 15; FPL Ex. 1 at 13). Nucor, NOAC, and NOPEC state that this rider will hinder the development of competitive markets for retail generation service. NOAC and NOPEC maintain that this unavoidable charge will greatly impede and likely destroy large-scale governmental aggregation (Nucor Ex. 3 at 31; NOAC/NOPEC Jt. Ex. 1 at 12, 18). FPL, NOAC, and NOPEC assert that Rider MDS should either be disallowed or made avoidable for large-scale governmental aggregations (FPL Br. at 5; NOAC/NOPEC Br. at 27). Moreover, IEU-Ohio contends that, if Rider MDS is intended to compensate FirstEnergy for hedging costs associated with serving its entire retail load, it is not clear what additional costs would result from shopping customers returning which would justify Standby Charges for Generation Rider (Rider SBC) (IEU-Ohio Ex. 1 at 7). Likewise, FPL believes that Rider SBC is designed to protect against the Companies' concern regarding risk. FPL asserts that, if Rider MDS is allowed as an unavoidable charge then, to ensure a level playing field, a pro-rated portion of the rider revenues should be made available to competitive suppliers serving large-scale government aggregations to mitigate any costs incurred due to shopping risk (FPL Ex. 1 at 13-14). Another alternative mentioned by NOAC and NOPEC is that Rider MDS could be made avoidable upon prior notice by a large-scale governmental aggregation that it will take competitive electric retail service from a third-party supplier (NOAC/NOPEC Br. at 34-35).

OEG contends that, to the extent the ESP can be modified to eliminate the Companies' volumetric risk to provide POLR services to some ESP customers, then those customers should not be charged the costs of that risk. Therefore, OEG recommends that

Rider MDS be waived for ESP customers who either: (1) agree to forgo their right to shop during the term of the ESP; or (2) agree to not take service under the ESP and, in the event that they return to POLR service, agree to accept market-based rates (OEG Ex. 1 at 26). Nucor supports OEG's proposal (Nucor Br. at 53). IEU-Ohio agrees with the second part of OEG's recommendation (IEU-Ohio Br. at 25).

FirstEnergy states that the criticisms from the intervenors that Rider MDS is not cost-based are misdirected. According to FirstEnergy, an ESP is not a cost-based vehicle and, therefore, such a calculation is not a prerequisite. FirstEnergy contends that it is only able to offer the fixed base generation prices set forth in the ESP if it can be compensated for the risks arising from a customer's ability to shop via Rider MDS (Co. Br. at 49). Furthermore, in response to proposals by various parties that Rider MDS be made avoidable under certain circumstances, i.e., the customer agreeing not to shop, FirstEnergy points out that these proposals do not eliminate shopping or the risks associated with the Companies' POLR supply obligation which Rider MDS is intended to cover (Co. Reply Br. at 40-41).

The Commission agrees with the intervenors who question the purpose of Rider MDS. We do not believe that the record supports the imposition of Rider MDS, especially in light of the possibility that the impact of Rider MDS would impede shopping. Therefore, the Commission finds that Rider MDS should not be approved. Accordingly, the Commission finds that FirstEnergy's proposed ESP should be modified to eliminate Rider MDS.

4. Standby Charges for Generation (Rider SBC)

Pursuant to the ESP, Rider SBC would be an avoidable rider that would compensate the Companies for the risk of customers coming back to the electric utility during times of rising prices. The proposed Rider SBC is 1.5 cents per kWh in 2009, 2.0 cents per kWh in 2010, and 2.5 cents per kWh in 2011 (Co. Ex. 9a at 15-16). Pursuant to the ESP, customers, either individually or as part of a governmental aggregation group, who switch to an alternative generation supplier may elect to waive standby charges (Co. Ex. 9a at 16). If the customer pays the standby charge while taking generation service from an alternative supplier, the customer will have the right to return to the Companies' SSO price, provided the customer remains with the electric utility for a period not less than 12 months or the remainder of the ESP (Co. Ex. 5 at 21). If a customer chooses not to pay the standby charges, should they return to the Companies for generation service during the ESP period, they would do so at the market pricing for generation; for returning non-governmental customers who do not pay the standby charges, they will pay the higher of the SSO market pricing or the SSO pricing otherwise applicable to such customers. Customers who do not pay Rider SBC have no minimum stay provision if they return to the electric utility (Co. Ex. 9a at 16).

Staff believes that a minimum stay provision discourages market development. Therefore, Staff recommends that, for residential and small commercial customers who pay the standby charge and then choose to return to the Companies' SSO price, no minimum stay requirement should be imposed. However, if a minimum stay is approved, Staff recommends that it apply only to residential and small commercial customers who return in the summer (May 16th through September 15th) (Staff Ex. 8 at 10). The Competitive Suppliers submit that Rider SBC should be modified so that it does not act as a penalty for customers who return to the SSO (Comp. Supp. Br. at 22).

IEU-Ohio and Cleveland maintain that Rider SBC is arbitrary and unreasonable (IEU-Ohio Ex. 1 at 7; Cleve. Ex. 1 at 5). As discussed previously, IEU-Ohio insists that, if Rider MDS is intended to compensate for hedging costs associated with serving its entire retail load, it is not clear what additional costs would result from shopping customers returning which would justify Rider SBC (IEU-Ohio Ex. 1 at 7). While IEU-Ohio believes it is reasonable for the Companies to recover the costs of hedging risk, IEU-Ohio believes that, initially, Rider SBC should be set at \$0 and then the Companies could file periodic requests to update the rate to reflect actual, prudently incurred hedging costs (IEU-Ohio Br. at 25-26).

The Commission believes that Rider SBC complies with the provisions of Section 4928.20(J), Revised Code, which requires that customers of aggregations be permitted to avoid charges for standby power by agreeing not to return to the rate provided under the ESP; instead such customers would pay a market rate in the event of a return to electric utility service. It is also important to note that this rider is entirely optional to individual customers. The record reflects that Rider SBC, as proposed, is not based upon cost (Tr. 1 at 90-91). The Commission finds that FirstEnergy's proposed ESP should be modified such that Rider SBC will be based upon the actual, prudently-incurred costs to FirstEnergy of hedging against the risk of customers returning to the SSO (Tr. 1 at 92-93). Therefore, while the Commission will accept FirstEnergy's proposed rate of \$0.015 per kWh, this rate will be subject to Commission review and reconciliation on a quarterly basis to insure that it reflects the Companies' actual prudently-incurred costs. Further, the Commission agrees with Staff witness Turkenton that there should be no minimum stay for returning residential and small commercial customers (Staff Ex. 8 at 10). Next, we believe that the definitions should be clarified such that the market pricing for generation applicable to customers who choose not to pay Rider SBC and then return to the Companies for generation service will be based on the quarterly forward wholesale on-peak and off-peak price multiplied by 120. Accordingly, the Commission finds that Rider SBC should be approved as modified herein.

5. Adjustments to the Base Generation Charges - Fuel Transportation Surcharge, Environmental Control, and New Taxes (Rider FTE) and Fuel Cost Adjustment (Rider FCA)

Pursuant to the ESP, Fuel Transportation Surcharge, Environmental Control, and New Taxes Rider (Rider FTE) and Fuel Cost Adjustment Rider (Rider FCA) would be avoidable riders that would constitute adjustments to the base generation charges proposed in the ESP. These riders would be averaged over the three Companies' sales in aggregate, would be adjusted on a quarterly basis, and the adjustment would include a reconciliation component for the balance of the actual recoverable costs, including interest (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 14, 16).

(a) Rider FTE

Specifically, Rider FTE would be effective beginning January 1, 2009. The Companies explain that Rider FTE would recover two categories of costs. First, it would recover increases in fuel transportation surcharges imposed by shippers in excess of a baseline level of \$30 million in 2009, \$20 million in 2010, and \$10 million in 2011. Second, Rider FTE would recover costs associated with new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws effective after January 1, 2008, to the extent such costs exceed \$50 million during the ESP and are related to the generation assets of FES (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 13-14). OCC recommends that Rider FTE be rejected (OCC Ex. 3 at 38).

With regard to the fuel transportation portion of Rider FTE, Staff points out that the baseline levels for this portion of the rider, \$30, \$20, and \$10 million, were determined by the Companies based on the judgment of the Companies' management and are reflective of the risk the Companies were willing to take during the ESP period (Staff Ex. 8 at 5). Based upon the fact that the ESP could terminate early, prior to when the recovery of the bulk of any fuel transportation costs would be sought, and, given the fact that no specific fuel transportation forecast or analysis has been provided by the Companies, Staff recommends that the fuel transportation portion of Rider FTE not be approved (Staff Ex. 8 at 6). However, if the Commission were to approve the fuel transportation portion of Rider FTE, Staff recommends that, consistent with SB 221, the Staff be able to audit all current renegotiated and any new contracts to ensure that any such surcharges in the contracts were warranted and prudent (Staff Ex. 8 at 6).

Further, with regard to the fuel transportation portion of Rider FTE, FPL advocates that the charge should be based on actual historical costs. In order to ensure a level playing field, FPL states that FirstEnergy must develop a transparent charge to cover these fuel transportation surcharges (FPL Ex. 1 at 22). In response to the concern that the costs for the fuel transportation portion be transparent, the Companies believe that this concern

is unfounded because the Companies have already provided supporting information for the costs for 2006 and 2007, as well as a budget forecast for the term of the ESP, to the Staff and, under the ESP, the Commission will have the opportunity to audit and review these costs (Co. Br. at 28).

Staff supports the approval of the second portion of Rider FTE pertaining to new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws. Staff agrees that initially this portion of Rider FTE should be funded at \$0 and used as placeholder in the event costs exceed \$50 million during the ESP. Moreover, Staff recommends that, since many of these costs are unknown at this time, the Companies should be required to consult with Staff regarding the types of costs to be included in the rider. Overall, Staff recommends that Rider FTE be subject to audits by Staff and reviewed in a separate annual proceeding outside of the automatic recovery provision of the ESP (Staff Ex. 8 at 7-8). In response, FirstEnergy clarifies that, as proposed, the Commission would review all costs that may be included in recovery for Rider FTE (Tr. 11 at 135-136, 150; Co. Reply Br. at 53).

Upon consideration of the evidence in the record, the Commission finds that the fuel transportation portion of Rider FTE should not be approved. With regard to the new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws portion of rider FTE, we agree with Staff that it should be funded at \$0 and that the Companies may file a request for recovery to the extent that such costs are above the baseline \$50 million during the ESP. In addition, we find that the Companies should consult with Staff regarding the types of costs to be included in this rider and that this rider should be subject to audits by Staff. Accordingly, FirstEnergy's Rider FTE, as proposed in the ESP, should be modified as set forth herein.

(b) Rider FCA

According to the Companies, Rider FCA would be effective for services rendered beginning January 1, 2011. Given the uncertainty of fuel prices more than two years out, the Companies have proposed Rider FCA to recover the costs of fuel in 2011 above the level of fuel costs incurred in 2010 (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 15).

Staff recommends, and OCC agrees, that Rider FCA should not be approved given the uncertainty surrounding whether the Companies' proposed ESP will ultimately be a two-year or three-year plan, and because the Companies have not provided a forecast of the 2011 Rider FCA fuel costs on which to base an opinion (Staff Ex. 8 at 4; OCC Ex. 3 at 38).

In light of the significant reductions ordered by the Commission to the proposed base generation rate for 2011, we find that Rider FCA should be approved as proposed by FirstEnergy. However, the Commission directs FirstEnergy to provide Staff with a fully-

documented forecast of fuel costs for 2011 within ninety days after the issuance of this order.

6. Non-distribution Service Uncollectible Rider (Rider NDU) and PIPP Uncollectible Rider (Rider PUR)

Pursuant to the ESP, the Non-distribution Service Uncollectible Rider (Rider NDU) would be an unavoidable rider that would compensate the Companies for the risk of customer non-payment for non-distribution service and would be initially set at the average rate of .0403 cents per kWh for each of the Companies. This rider would be reconciled annually to reflect actual uncollectible non-distribution costs (Co. Ex. 9a at 15).

The Companies propose that, to provide for recovery of uncollectible expense associated with percentage of income payment plan (PIPP) customers, to the extent such an expense is incurred by the Companies as a result of modification of the state policy after July 31, 2008, PIPP Uncollectible Rider (Rider PUR) would be implemented. Rider PUR would be an unavoidable rider and would be initially set at 0.00 cents per kWh. This rider would be updated and reconciled on an annual basis (Co. Ex. 9a at 15). The Companies explain that Rider PUR is a placeholder for additional costs if the state makes changes that require them to bear uncollectible costs for PIPP customers (Co. Br. at 53).

In support of the proposal that Riders NDU and PUR be unavoidable by shopping customers, FirstEnergy submits that both of the riders promote social objectives and, therefore, it is appropriate for the Companies to recover the totality of the uncollectible accounts. FirstEnergy states that, in contrast to the Companies, which serve as the default service provider, competitive retail electric service (CRES) providers can establish their own credit rules to minimize uncollectible accounts (Co. Ex. 4 at 12-14).

Staff recommends, and the Competitive Suppliers agree, that Rider NDU should be avoidable for customers who shop because a customer who is not receiving generation service from FirstEnergy should not be responsible for generation-related costs incurred by FirstEnergy (Staff Ex. 5 at 8; Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8).

The Commercial Group opposes approval of Rider NDU stating that a rider that allows the Companies to pass on such costs removes all incentive for the Companies to manage this expense (Comm. Gr. Ex. 1 at 13). In addition, the Commercial Group notes that Rider NDU will be allocated to customers on a cents per kWh basis; they believe that an energy allocation of the costs is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). OPAE also recommends that Riders NDU and PUR be rejected stating that uncollectible expenses are already reflected in FirstEnergy's base rates and these riders would allow for double recovery (OPAE Ex. 1 at 32).

NOAC, NOPEC, and FPL believe that an unavoidable Rider NDU creates an unfair competitive subsidy for the Companies. To eliminate this subsidy, NOAC, NOPEC, and FPL propose that the Companies be required to purchase 100 percent of the receivables from any CRES provider billing through the Companies (NOAC/NOPEC Jt. Ex. 1 at 20-21; FPL Ex. 1 at 20). Integrys agrees that, if FirstEnergy insists on providing an unavoidable charge through Rider NDU, it should be required to provide a purchase of receivables program for competitive suppliers with a zero percent discount rate (Comp. Supp. Ex. 3 at 11). In the alternative, FPL recommends that Rider NDU should be made avoidable (FPL Br. at 39). The Consumer Advocates agree that FirstEnergy should either purchase the receivables from competitive suppliers or the rider should be avoidable (Con. Adv. Br. at 13).

With regard to Rider NDU, we acknowledge FirstEnergy's perspective that the recovery of uncollectibles supports a social objective; however, we cannot ignore the fact that the competitive suppliers have uncollectibles of their own that they must face. Taking this into consideration, the Commission finds that the arguments presented by some of the parties that Rider NDU should be avoidable by shopping customers are reasonable; therefore, this proposal should be adopted in the ESP and Rider NDU should be avoidable. We would note that this conclusion is consistent with our recent decision in *in re FirstEnergy*, Case No. 08-936-EL-SSO, Opinion & Order (November 25, 2008). Accordingly, the Commission finds that Rider NDU should be modified to reflect that it will be avoidable for shopping customers. Finally, with regard to Rider PUR, the Commission finds that it should be approved as proposed by FirstEnergy. The Commission notes, however, that, in our annual review and reconciliation of Riders NDU and PUR, we will require FirstEnergy to demonstrate that it actively pursues collection of unpaid balances and that its collection mechanisms effectively mitigate the volume of uncollectibles.

7. Renewable Energy Resource Requirements

Section 4928.64, Revised Code, establishes an alternative energy portfolio standard (AEPS) comprised of requirements for both renewable and advanced energy resources. Specifically, Section 4928.64(B)(2), Revised Code, introduces specific annual benchmarks for renewable energy resources and solar energy resources beginning in 2009 (Staff Ex. 1 at 2).

The Companies explain that the base generation prices also include all of the costs associated with the Companies' renewable energy resource requirement during the ESP and/or equivalent cost for renewable credits (Co. Ex. 9a at 11). According to the Companies, the renewable energy resources will be acquired in sufficient amounts to comply with the requirements of SB 221, as set forth in Section 4928.64, Revised Code, without additional charge for the duration of the ESP period.

Staff notes that the Companies failed to detail in the application how they expect to comply with the AEPS statutory requirements during the ESP period (Staff Ex. 1 at 3). Staff points out Section 4928.64(C)(3), Revised Code, includes language that excuses electric distribution utilities and electric service companies from complying with the annual AEPS benchmarks if their respective annual compliance costs exceed a certain level. Staff is concerned that the reduction in the base generation rates through the use of deferrals could impact the implementation of this statute; however, until the Commission issues final rules in Case No. 08-888-EL-ORD (*Alternative and Renewable Energy Rules*) which address AEPS, it is not possible to identify the impacts, if any, that the deferrals may have on the cost cap calculations (Staff Ex. 1 at 5).

The Commission notes that, under the terms of the application filed by FirstEnergy, the costs of compliance for the renewable energy requirements under Section 4928.64(B)(2), Revised Code, are included in the modified base generation rates. Thus, customers will see no increase in rates for compliance with the renewable energy standards for 2009, 2010, and 2011 (Co. Ex. 9a at 11).

8. Green Resource Rider (Rider GRN)

The Companies state that, during the ESP period, the Companies will offer a green resource program through a Renewable Energy Resource Requirements and Green Resource Rider (Rider GRN), similar to the one approved in Case No. 06-1112- EL-UNC (*FirstEnergy Generation Competitive Bid Process Case*). The continuation of this rider will allow residential customers the opportunity to support alternative energy resources through the purchase of renewable energy certificates (RECs) (Co. Ex. 9a at 11; Co. Ex. 4 at 8; Co. Ex. 5 at 7).

Staff supports the Companies' proposal to continue the voluntary green product offering through Rider GRN during the ESP. Staff notes that the current Rider GRN approved in the *FirstEnergy Generation Competitive Bid Process Case* ends December 31, 2008. Staff points out that the current rider amount was determined by two independent requests for proposals which used two different definitions for RECs, one used the "green-e" renewable definition and the other used the alternative energy definition set forth in the May 27, 2007, stipulation in the *FirstEnergy Generation Competitive Bid Process Case*. Staff recommends that only the "green-e" renewable definition be used for purposes of the Rider GRN to be implemented during the ESP (Staff Ex. 8 at 11-13).

The Commission agrees with Staff witness Turkenton that only the RECs which meet the "green-e" definition should be used for purposes of Rider GRN (Staff Ex. 8 at 11-12). Therefore, the Commission finds that the ESP should be modified to clarify that only RECs which meet the "green-e" definition will be used for purposes of Rider GRN. Accordingly, Rider GRN should be approved as modified herein.

G. Distribution

1. Resolution of FirstEnergy Distribution Rate Case - Case No. 07-551-EL-AIR

FirstEnergy conditioned its ESP application upon a resolution of the *FirstEnergy Distribution Rate Case*, in which FirstEnergy proposes that a distribution rate increase is granted in the amount of \$75 million for OE, \$34.5 million for CEI, and \$40.5 million for TE (Co. Ex. 9a at 19). According to FirstEnergy, the aggregate revenues from the distribution rate case expected by the Companies is \$150 million per year (Co. Ex. 1 at 18). In addition, approval of the ESP would include: (1) an allowed rate of return on equity (ROE), in the distribution rate case, of 10.5 percent (2) approval of the revenue distribution and rate design stipulation submitted in the distribution rate case; and (3) approval of the Companies' proposed distribution tariffs (Co. Ex. 9a at 20).

The Commercial Group argues that the Companies' proposal in the ESP for a modified version of the distribution rate increase has not been shown to be reasonable and should not be permitted. Furthermore, the Commercial Group states that the proposed 10.5 percent ROE is excessive and has not been shown to be appropriate in light of the significant risk reduction aspect of SB 221 and FirstEnergy's use of automatic rate adjustment riders in the ESP. The Commercial Group believes that an ROE of around ten percent would be more appropriate, with a common equity ratio of total capital structure used to develop rates of no higher than 50 percent if the ESP riders and deferred cost recovery proposal are permitted (Com. Gr. Ex. 1 at 15).

As stated previously, the Commission declines to resolve in this case the substantive issues of the *FirstEnergy Distribution Rate Case*. The *FirstEnergy Distribution Rate Case* will be decided solely based upon the evidence in the record of that proceeding, and it is our intention to resolve those matters in the near future. At this time, however, the ESP, as modified by this order, does not include matters more appropriately reserved for the *FirstEnergy Distribution Rate Case* and our approval of FirstEnergy's application for an ESP should not be construed as our acceptance of the proposed resolution of any of the issues in the *FirstEnergy Distribution Rate Case*.

2. Distribution Rate Freeze

The ESP provides that the new distribution base rates pending in the *FirstEnergy Distribution Rate Case* would be effective for OE and TE on January 1, 2009, and effective for CEI on May 1, 2009 (Co. Ex. 9a at 19). There is a commitment in the ESP to keep these rates in place through 2013, absent limited unforeseeable circumstances (Co. Ex. 9a at 5).

Considering the proposed rate freeze, in conjunction with other provisions of the ESP, Staff recommends against the five-year rate freeze. Staff believes that the provisions

of the ESP which give the Companies the ability to defer distribution costs to be included in future rate cases and to adjust rates for certain line items should be considered in a comprehensive rate proceeding where the components of the distribution revenue requirement can be reviewed (Staff Ex. 5 at 6). Kroger and the Consumer Advocates agree that the distribution rate freeze and the distribution deferrals should not be approved and, if the Companies find it necessary to file a rate case, they should do so (Kroger Ex. 1 at 14; Con. Adv. Br. at 40-41).

The Commission finds that FirstEnergy's application should be modified to eliminate the proposed distribution rate freeze. As noted by Staff witness Fortney, FirstEnergy has proposed a number of new distribution deferrals which are linked to the proposed distribution rate freeze (Staff Ex. 5 at 5-8). As we discuss below, the Commission does not believe that additional distribution deferrals are necessary or appropriate at this time. We believe that it would be unfair to FirstEnergy to accept the proposed distribution rate freeze while rejecting the request for deferral authority. Accordingly, FirstEnergy's ESP should be modified to eliminate the proposed distribution rate freeze.

3. CEI and Distribution Service Rider

The Distribution Service Rider proposed in the ESP is only applicable to CEI customers from January 1, 2009, through April 30, 2009. FirstEnergy explains that this rider is necessary because the proposed non-distribution tariffs will be effective January 1, 2009, under the new rate schedule classifications proposed in the *FirstEnergy Distribution Rate Case*, but the proposed distribution tariff changes are not effective until May 1, 2009. Therefore, the Companies state that this rider provides a means of integrating the new rate classifications with the current rate schedule distribution related charges. The Distribution Service Rider will not be effective after April 30, 2009, when the distribution charges will be calculated based on the new proposed rate classifications (Co. Ex. 4 at 7). The Commission finds that, because we have retained the existing rate design and tariff structure for generation rates, there is no mismatch of rate design to address. Therefore, the proposed Distribution Service Rider for CEI is unnecessary and the ESP should be modified to eliminate this rider.

4. Additional Deferred Distribution Costs - Storm Damage and Distribution Enhancement Rider

The ESP provides that, during the period January 1, 2009, through December 31, 2013, the Companies, in the aggregate, may defer certain distribution costs and expenses. Pursuant to the ESP, the Storm Damage and Distribution Enhancement Rider would be an unavoidable rider that would recover deferrals for: (1) storm damage expenses in excess of \$13.9 million annually; (2) additional costs, including post-in-service carrying charges, resulting from any changes in the recovery of line extension costs, as a result of rules or policies implemented pursuant to Section 4928.151, Revised Code, compared to the

Companies' proposal in the *FirstEnergy Distribution Rate Case*; and (3) depreciation, property tax obligations, and post-in-service carrying charges on gross plant distribution capital investments placed in service after December 31, 2008, and made to improve reliability and/or enhance the efficiency of the distribution system. The Companies request that the interest on these items be deferred monthly during the period of January 1, 2009, through December 31, 2013, at a rate of 0.7083 percent. This rider would commence on January 1, 2014, and continue for a ten-year period (Co. Ex. 9a at 22; Co. Ex. 2 at 4).

OCC believes that continued use of deferrals regarding line extensions should end (OCC Ex. 1 at 37). The Commercial Group submits that the Companies' proposed rate moratorium coupled with deferrals of the revenue requirements associated with new line extensions and new plant investments will result in the over-recovery of distribution investment costs (Com. Gr. Ex. 1 at 17). Staff recommends that the Companies be permitted to apply to the Commission for recovery of incremental storm damage expenses (Staff Br. at 12).

The Commission agrees with Staff witness Fortney that the expenses which the Companies seek to recover through this rider are best reviewed in a distribution rate case where all components of distribution rates are subject to review (Staff Ex. 5 at 7-8). Further, as discussed above, we have modified FirstEnergy's ESP to eliminate the proposed distribution rate freeze. Therefore, we find that the additional distribution deferrals are neither necessary nor appropriate at this time. Accordingly, the Companies' ESP should be modified to eliminate the distribution deferrals.

5. System Average Interruption Duration Index (SAIDI) Reliability Performance

The Companies are proposing in the ESP that appropriate system average interruption duration index (SAIDI) performance targets be established and that they be designed with performance incentives for the Companies which are skewed to benefit customers (Co. Ex. 9a at 6). Currently, the SAIDI target for TE and OE is 120 minutes and the target for CEI is 95 minutes (Co. Ex. 9a at 21; Co. Ex. 3 at 5). The Companies are proposing that the SAIDI target for CEI be revised to 120 minutes (Co. Ex. 9a at 21; Co. Ex. 3 at 6). In support of the modified SAIDI for CEI, the Companies state that CEI has the most aged distribution system of the three electric utilities and CEI's system design and service area geography make it more difficult that the other two companies to maintain a low SAIDI (Co. Ex. 3 at 6).

According to the ESP, the proposed 120 minute SAIDI targets would be coupled with a reliability performance band between 90 minutes and 135 minutes from January 1, 2009, through December 31, 2013 (Co. Ex. 9a, Att. E). FirstEnergy believes that a performance band is necessary because it recognizes that, with changing weather

conditions and other factors outside of the Companies' control, using an absolute number as a performance criterion is not practical. The Companies argue that the proposed performance band is asymmetrically skewed to benefit customers. Furthermore, they contend that, regardless of whether the Companies perform at the high end or the low end of the proposed band, they would remain in the first or second quartile of industry performance (Co. Ex. 3 at 8).

In order to ensure that reliability is measured on an apples-to-apples basis between the three electric utilities, the Companies propose a rear lot reduction factor for CEI, which is a mechanism that establishes an outage duration time which takes into consideration the challenges of rear lot construction in CEI's service area. This mechanism would only apply to CEI and it would multiply CEI's customer outage minutes by a factor of .5 on such circuits where 50 percent or more of the premises are served by rear lot facilities (Co. Ex. 9a, Att. E; Co. Ex. 3 at 6-7). According to the Companies, CEI has 439 circuits where over 50 percent of the customers on those circuits are served from rear lot facilities (Co. Ex. 9a at 9; Co. Ex. 3 at 7; Tr. III at 254). These 439 circuits represent slightly less than 50 percent of CEI's total number of circuits of 1,086 (Co. Ex. 9a at 9; Co. Ex. 3 at 7; OCC Ex. 2 at 28).

The Companies propose that, for purposes of the ESP and all reporting requirements pursuant to Rule 4901:1-10, Ohio Administrative Code (O.A.C.), each of the Companies' SAIDI targets be calculated using the methodology that has been accepted by the Staff, including that major storm exclusions are generally defined as events affecting six percent of the customers in a 12-hour period (Co. Ex. 9a, Att. E).

In response to the Companies' proposal, Staff states that it does not believe that SAIDI should be the only performance measurement to determine the level of electric service that an electric utility should provide its customers (Staff Ex. 3 at 6). In addition, Staff does not support the Companies' proposal to apply a performance band to the SAIDI performance targets. Staff has always considered performance targets to be minimum performance levels and, when a minimum level is not met, then the electric utility must provide an action plan. Under the Companies' proposal, if a minimum level is not met, the Companies are not required to provide an action plan to improve service. Further, as far as performing better than the minimum, Staff believes that all electric utilities should strive to perform better than their minimum targets (Staff Ex. 3 at 9).

In addition, both Staff and OCC oppose the rear lot reduction proposal for CEI's performance index (Staff Ex. 3 at 6; OCC Ex. 2 at 26). OCC believes that the proposed increase in the SAIDI target for CEI to 120 minutes will mitigate any potential impact due to rear lot construction (OCC Ex. 2 at 30).

The Commission notes that there is substantial evidence in the record that the proposed SAIDI adjustment should be considered. According to the record in this case, CEI's SAIDI target is 95 minutes (Co. Ex. 3 at 5). FirstEnergy witness Schneider testified that a recent study by the Institute of Electrical and Electronics Engineers indicated that a SAIDI performance of 89 would be in the top decile of performance of 100 electric distribution companies while a SAIDI performance of 135 would be in the middle of the second quartile. (Co. Ex. 3 at 9). Staff witness Roberts agreed that this study is entitled to be given weight by the Commission (Tr. VII at 318-319). Therefore, based upon the evidence in the record, in order to meet its SAIDI target of 95, CEI's SAIDI would need to be nearly in the top decile of electric distribution companies in this country and well above the middle of the second quartile. Further, Staff witness Roberts testified that CEI could meet this target only under "perfect" or "near perfect" conditions (Tr. VII at 308-309).

Further, the Commission points out that Chapter 4901:1-10, O.A.C., contains rules for amending electric service reliability targets and, in Case No. 06-653-EL-ORD (*Electric Service and Safety Standards*), we recently adopted new rules in this chapter for amending electric service reliability standards. Although the evidence in the record indicates that the change in the SAIDI target may be reasonable, the Commission believes that the established process, set forth in Chapter 4901:1-10, O.A.C., for amending electric service reliability targets with the agreement of the Staff should be followed. Further, if an electric utility and Staff cannot agree upon a revision to a reliability target, the rules provide that they may seek a hearing before the Commission to resolve the dispute. Therefore, FirstEnergy should follow this established process for setting distribution reliability targets if it believes that conditions warrant a downward revision of its SAIDI target. Likewise, with regard to FirstEnergy's request for a rear lot reduction factor for CEI, FirstEnergy should present its arguments for this factor in conjunction with its proposal for a revision to CEI's SAIDI target. Accordingly, we will decline to amend CEI's SAIDI target, and we will modify FirstEnergy's ESP to eliminate the proposed change to the SAIDI target, as well as the implementation of a rear lot reduction factor.

6. Distribution Service Improvement Rider (Rider DSI)

The Companies explain that, consistent with Section 4928.143(B)(2)(h), Revised Code, they are proposing a Distribution Service Improvement Rider (Rider DSI) (Co. Ex. 9a, Att. E). Rider DSI would be an unavoidable rider that would ensure that the expectations of the Companies and the customers pertaining to distribution reliability are aligned. According to the Companies, Rider DSI would help them manage the increasing costs of providing electric distribution service, the need to extend capital for equipment earlier than before, the need to train new employees to replace retirees, the need to replace components of an aging distribution system, the importance of reliability, and the emergence of new technology, such as Smart Grid technology (Co. Ex. 9a at 21; Co. Ex. 3 at 3-4). Rider DSI would be effective from January 1, 2009, through December 31, 2011 (Co. Ex. 9a at 21; Co. Ex. 3 at 4). This rider would be adjusted up or down by up to 15 percent

annually, based upon the Companies meeting certain goals related to distribution reliability, as reflected in the SAIDI performance adjustments (Co. Ex. 9a at 6, 21, Att. E; Co. Ex. 3 at 5). The Companies explain that, if an individual company's SAIDI performance for the previous reporting period is higher than 135 minutes, then Rider DSI would be adjusted downward; however, if a company's SAIDI performance is less than 90 minutes, then Rider DSI will be adjusted upward. Prior to this adjustment, the Companies state that the rider would, on average, be 0.2 cents per kWh in 2009 through 2011. For 2012 through 2013, Rider DSI would be set at 0.0 cents per kWh, but remain in place to effectuate any SAIDI performance adjustments (Co. Ex. 9a at 21, Att. E; Co. Ex. 3 at 5). The ESP provides that Rider DSI would not be considered a contribution in aid of construction or be used in any determination of excessive earnings (Co. Ex. 9a at 22; Co. Ex. 3 at 5).

Staff, OCC, OPAE, and Kroger oppose the Companies' proposal for Rider DSI, stating that it has no connection with recovery of actual costs (Staff Ex. 3 at 3; OCC Ex. 2 at 35; OPAE Ex. 1 at 28; Kroger Ex. 1 at 5). Staff states, and OPAE and OCC similarly agree, that the proposal does not contain defined programs with associated costs and benefits, nor does it quantify how much of the cost is incremental to current spending (Staff Ex. 3 at 3; OPAE Ex. 1 at 28; OCC Ex. 3 at 35). Staff believes that the items which the Companies are seeking recovery for in this rider are part of the day-to-day operations of any electric utility company and should not require special funding (Staff Ex. 3 at 3). Further, the Consumer Advocates note that Rider DSI is not properly structured as an incentive plan as required in Section 4928.143(B)(2)(h), Revised Code (Con. Adv. Br. at 31).

OCC, OPAE, and the Commercial Group believe that it is inappropriate to provide price enhancements to the Companies as part of Rider DSI for simply accomplishing what they are expected to provide (OCC Ex. 1 at 35; OPAE Ex. 1 at 31; Com. Gr. Ex. 1 at 17). However, OCC states that, if the Commission were to allow Rider DSI, it would not be opposed to the use of only SAIDI for adjustment of the proposed rider. OCC's research shows that from 2000 through 2007 the Companies had gone over the proposed 135 upper limit of the SAIDI band five times for CEI, twice for TE, and once for OE; for that same period TE went under the proposed 90 lower limit of the SAIDI band four times (OCC Ex. 2 at 22-24).

In response to the intervenors' comments, FirstEnergy emphasizes that this is not a cost-based proceeding. FirstEnergy states that Rider DSI is not based on historically incurred costs, rather, it takes advantage of the provisions in Section 4928.143, Revised Code, that permits the Companies to implement an incentive-based distribution charge. According to the Companies, Rider DSI provides an important incentive to them to achieve a level of service reliability (Co. Br. at 56-57).

The Commission finds that FirstEnergy demonstrated in the record that it faces increased costs due to the need for workforce replacements and for replacing

infrastructure (Co. Ex. 3 at 3-4). However, the Commission does not believe that a distribution rider should be approved, unless it is based on a reasonable, forward-looking modernization program and prudently incurred costs. At the hearing, Staff indicated that it could only support mechanisms such as Rider DSI if such mechanism is cost-based (Tr. VII at 302). The Commission believes that this is a sound policy. Although Section 4928.143(B)(2)(h), Revised Code, does provide for distribution modernization riders as part of an ESP, following the sound policy goals of Section 4928.02, Revised Code, the Commission believes that such riders should be based upon prudently incurred costs, including a reasonable return on investment for the electric utility. However, the Companies have not demonstrated that the proposed Rider DSI is based on a reasonable, forward-looking distribution modernization program. Moreover, the testimony in this case clearly represented that the proposed Rider DSI is not cost-based. The Commission does not believe that a distribution rider should be approved, unless the program is shown to comply with both the intent and the scope of the statute and that it is based upon prudently incurred costs. Accordingly, the Commission finds that Rider DSI, as proposed in the ESP, should be modified.

Our approval of Rider DSI is conditioned upon the Companies developing a distribution infrastructure improvement program that reflects the intent and scope of the statute that is inclusive of all infrastructure considerations including, but not limited to, improved workforce and asset utilization, workforce replacement, infrastructure replacement, present and future needs for service reliability and power quality, cybersecurity, facilitation of demand response, integration of distributed generation and storage (including electric vehicles), use of Smart Grid technologies, and AMI deployment. To that end, FirstEnergy should work with the Staff to develop a program which comports with this requirement.

Furthermore, while we will set Rider DSI initially at \$0.002 per kWh, we believe that this rider should be based on FirstEnergy's actual, prudently incurred costs, including a return on FirstEnergy's investment equal to the rate of return authorized in the *FirstEnergy Distribution Rate Case*. To that end, Rider DSI will be subject to Commission review and reconciliation on an annual basis. Accordingly, Rider DSI should be approved, as modified herein.

7. Capital Improvement Commitment to Distribution System

As part of the ESP, the Companies will commit to invest in the aggregate at least \$1 billion in capital improvements in their energy delivery systems through 2013 (Co. Ex. 9a at 6, 22; Co. Ex. 3 at 10). Staff supports this commitment by the Companies because it represents a continuation of the Companies' capital spending over the past five years (Staff Ex. 3 at 4).

The Consumer Advocates state that FirstEnergy's ESP, including the \$1 billion commitment in capital improvements, should not be approved. According to the Consumer Advocates, FirstEnergy has not forecasted any improvements in distribution reliability as a result of the commitment and no assurances have been given by FirstEnergy that its commitment to capital spending will have any beneficial effect on customers (Con. Adv. Br. at 50-51).

To ensure that consumers benefit from this commitment, the Commission finds that the Companies should work with staff to develop a capital improvement program that advances state policy and is consistent the distribution infrastructure modernization program described in our findings on Rider DSI. Accordingly, the Commission finds that FirstEnergy's capital improvement commitment, as proposed in the ESP, should be approved.

H. Regulatory Transition Charge and Residential Transition Rate Credit

The Companies propose to waive, on a services rendered basis, on or after January 1, 2009, further regulatory transition charges (RTCs) and extended RTCs for CEI customers, which would otherwise continue through 2010 (Co. Ex. 9a at 9; Co. Ex. 2 at 8). In addition, in accordance with the ESP, as of January 1, 2009, residential customers will not receive transition rate credits. The transition rate credits equate to \$5.00 per month for residential customers of CEI and TE, and \$1.50 per month for OE residential customers. Furthermore, the credits include a reduction of the RTC by 23.3 percent, 12.8 percent, and 11.4 percent for OE, CEI, and TE residential customers, respectively. These credits were approved in Case No. 99-1212-EL-ETP (*FirstEnergy Electric Transition Plan [ETP] Case*). FirstEnergy states that the value to customers over the period of the ESP of the waiver of the RTCs and extended RTCs, not the residential credits, is \$591 million (Co. Ex. 9a at 9; Co. Ex. 1 at 17).

The Commission finds that the Companies' proposal to waive the RTCs and extended RTCs for CEI customers and eliminate the transition rate credits effective January 1, 2009, is reasonable and should be approved.

I. AMI, Smart Grid, Energy Efficiency, Demand Response, Economic Development, and Job Retention

1. Energy Efficiency and Demand Response

Section 4928.66, Revised Code, require the electric utilities to implement energy efficiency programs that will achieve energy savings and peak demand programs designed to reduce the electric utility's peak demand. Specifically, an electric utility must achieve energy savings in 2009, 2010, and 2011 of .3 percent, .5 percent, and .7 percent, respectively, of the normalized annual kWh sales of the electric utility during the

preceding three calendar years. This savings continues to rise until the cumulative savings reach 22 percent by 2025. Peak demand must be reduced by one percent in 2009 and by .75 percent annually until 2018.

As part of the ESP, the Companies commit up to \$25 million to support energy efficiency and demand response programs (Co. Ex. 9a at 7). According to the Companies, they commit to provide up to \$5 million of investment each year from January 1, 2009, through December 31, 2013, for these programs and will not request recovery for these costs (Co. Ex. 9a at 25).

Staff supports the Companies' commitment to contribute shareholder money toward energy efficiency and demand reduction programs, but states that it is unlikely that such a funding level itself will meet the required statutory benchmarks (Staff Ex. 2 at 14). OCC and OEC agree that the funding level is not sufficient to meet the statutory requirements (OCC Ex. 1 at 7; OEC Ex. 1 at 4). OEC states that FirstEnergy would need to increase its annual spending to approximately \$28 million to reach the statutory energy saving requirement (OEC Ex. 1 at 10). OCC recommends that, in addition to the \$5 million per year of shareholder money, the ratepayers contribute approximately \$44 million per year, which equates to about \$24.25 per customer, for a total of \$49 million per year in order to meet the requirements. Further, OCC recommends that the remainder of the funding for DSM programs approved in Case No. 05-1125-EL-ATA et al. (*FirstEnergy Rate Certainty Plan [RCP] Case*) be used as part of the \$44 million ratepayer contribution for the first year of the ESP (OCC Ex. 1 at 7-8).

OCC, NRDC, OPAE, and OEC submit that the Companies' DSM proposal in the ESP is seriously lacking detail and insufficient (OCC Ex. 1 at 5; NRDC Ex. 1 at 3-4; OPAE Ex. 1 at 21; OEC Ex. 1 at 11;). OCC submits that, for FirstEnergy to fail to provide a more substantial DSM filing knowing that SB 221 requires a significant DSM portfolio is objectionable (OCC Ex. 1 at 5-6). OCC recommends that the Companies continue to fund their existing DSM programs and add DSM programs such as: programs for appliances, air-conditioning, and new construction for residential customers; programs for business and state office buildings; and programs for commercial and industrial customers. OCC recommends that the total resource cost test be used to evaluate the cost-effectiveness of the Companies' energy efficiency programs (OCC Ex. 1 at 10-11). COSE agrees that the Companies should specifically include small business and commercial class customers in the ESP energy efficiency education and demand management activities. Further, COSE believes that a specific minimum allocation of resources to commercial class customers should be included in the ESP (COSE Ex. 1 at 2-4).

OPAE notes that the plan fails to provide any significant energy efficiency program targeted to at-risk populations. OPAE states that FirstEnergy should fund a substantial expansion of current programs aimed at low-income, elderly, and at-risk residential

customers as part of the overall efficiency and DSM portfolio of programs. In addition, OPAE requests that the Companies be ordered to continue to fund the existing low-income programs until a collaborative can develop a comprehensive portfolio of programs (OPAE Ex. 1 at 23; OPAE Br. at 8-9).

IEU-Ohio submits that customer-sited capabilities are a means that an electric utility may use to comply with the portfolio requirements of SB 221. However, IEU-Ohio points out that the ESP fails to set forth the details regarding how customer-sited capabilities will be relied on to meet this requirement; therefore, IEU-Ohio proposes that FirstEnergy be ordered to supplement the application and provide additional specificity on how the customer-sited capabilities will be accommodated under the ESP (IEU-Ohio Ex. 1 at 5; IEU-Ohio Br. at 18). OHA agrees that FirstEnergy should be required to create a plan that encourages the use of customer-sited generation in order to satisfy the portfolio requirements under the statute (OHA Br. at 20-21). The Commercial Group recommends that the programs be expanded to provide an option for customers to participate in wholesale demand response programs or other such programs at the wholesale level (Com. Gr. Ex. 1 at 9).

Staff, NRDC, OPAE, Citizens' Coalition, and OCC recommend that a collaborative process be formed with respect to the selection and development of energy efficiency and peak demand programs (Staff Ex. 2 at 14; NRDC Ex. 1 at 8; OPAE Ex. 1 at 22; Cit. Coal. Br. at 4; OCC Ex. 1 at 8). In addition, Staff recommends that the Companies contract with an independent third-party to measure and verify the energy and peak reduction savings for the programs (Staff Ex. 2 at 14). OCC also suggests that another option might be for the Companies to develop a standard DSM offer, with collaborative input, and pay a third-party provider of the energy efficiency a fixed kWh charge (OCC Ex. 1 at 9). OPAE agrees that the collaborative should hire a third-party administrator (OPAE Ex. 1 at 23). NRDC submits that, in this case, a third-party administrator should be selected through a competitive bid process because, according to NRDC, the Companies have limited experience with energy efficiency and have shown little desire to develop a comprehensive range of programs. NRDC believes that the third-party administrator should be paid for out of ratepayer funds (NRDC Ex. 1 at 5, 8-9).

In determining the appropriate benchmarks for meeting the statutory requirements, Staff recommends that the Companies use a 30-year rolling average of weather data with a 65-degree day as part of their forecasting method to determine weather normalized sales and peak load (Staff Ex. 2 at 9). In addition, Staff recommends that the Companies evaluate their current programs and consider and undertake a market potential study that will include an analysis of the appropriate program designs that will result in the Companies achieving the required statutory benchmarks. With regard to the inclusion of the energy savings and peak demand reductions from mercantile customers to be committed to the Companies for integration, if the Companies would like to count such

efforts toward their benchmarks, Staff states that they would need to submit such requests to the Commission for consideration on a case-by-case basis. As for interruptible programs counting toward annual benchmarks, Staff believes that such reductions would have to actually occur to be credited (Staff Ex. 2 at 12-13).

In response to the criticisms of the energy efficiency and demand response proposal in the ESP, FirstEnergy states that its commitment to spend up to \$25 million of shareholder funds on the programs should not be taken to mean that this is the upper limit of what it will spend to meet the benchmarks in Section 4928.66, Revised Code. FirstEnergy believes that the concerns raised by the intervenors are premature and that they would best be addressed in a future proceeding dedicated to reviewing the Companies' benchmark report that will be filed in conformance with the Commission's rules and the statute (Co. Br. at 36).

The Commission notes that Section 4928.66, Revised Code, requires electric utilities to meet certain energy efficiency and demand response requirements and to advance state goals. Like some of the intervenors, we believe that FirstEnergy has yet to develop energy efficiency and demand response programs sufficient to comply with those obligations. To assist with that endeavor, the Commission agrees with the recommendation of numerous intervenors that a collaborative process should be formed with respect to the selection and development of energy efficiency and peak demand programs. Therefore, FirstEnergy should initiate a collaborative in order to assist the Companies in meeting their obligations.

Turning now to the commitment of funds set forth in the proposed ESP, the Commission notes that, regardless of the commitment attested to in the plan, it is the Companies' duty to meet the energy efficiency and demand response requirements set forth in the statute and to comply with any rules adopted thereunder. The provisions of Section 4928.66(C), Revised Code, have been determined by the General Assembly to be a sufficient enforcement mechanism to ensure electric utilities' compliance with the energy efficiency and demand response requirements, and the Companies will be expected to make the expenditures necessary to meet those requirements. With an, as yet undefined program, the Commission believes that it is meaningless for the Companies to set forth any dollar figure in the plan because, regardless of the dollar amount set forth in the plan, the Companies are bound by the statute to comply with the energy efficiency and demand response requirements. Accordingly, the Commission finds that Companies' application should be modified to eliminate the proposed commitment of funds.

2. Demand Side Management and Energy Efficiency (Rider DSE)

Pursuant to the ESP, Rider DSE would recover costs incurred by the Companies associated with energy efficiency, peak load reduction, and DSM programs, including recovery of lost distribution revenues resulting from implementation of such programs

and any unrecovered DSM program costs from the *FirstEnergy RCP Case* (Co. Ex. 9a at 27). Rider DSE includes two components which are updated semi-annually: DSE1, which is a \$0.0193 per kWh charge; and DSE2, which reimburses the Companies for past and future costs incurred in complying with energy efficiency and peak demand reduction requirements, including costs for programs approved in the *FirstEnergy RCP Case* (Co. Sch. 5o at 16-17; Co. Br. at 39). The Companies explain that, as permitted by Section 4928.143(B)(2)(i), since the Companies are part of the same holding company, this rider will be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 28). As explained by FirstEnergy, customers may avoid Rider DSE2 by implementing customer-sited programs that help the Companies secure compliance with Section 4928.66, Revised Code (Co. Ex. 4 at 11).

IEU-Ohio notes that customers are not eligible to avoid DSE2 charges if they are taking service under either a unique arrangement or the Reasonable Arrangements Rider (Rider RAR). IEU-Ohio believes that this limitation is contrary to Section 4928.66(A)(2)(c), Revised Code (Co. Ex. 9c at 62; IEU-Ohio Br. at 19). Furthermore, IEU-Ohio points out that Rider DSE2 is initially set a \$0 in the ESP and the earliest date this charge could increase for non-residential customers would be January 1, 2010. Therefore, IEU-Ohio states that, at least initially, the avoidability of the rider will not provide any economic incentives to implement customer-sited capabilities (IEU-Ohio Ex. 1 at 5). Contrary to IEU-Ohio's understanding, the Companies clarify that costs to be recovered as part of the DSE2 charge for non-residential customers will be included in the rider as early as mid-2009. The Companies believe that, if the estimates by certain parties are accurate, the costs to implement programs in 2009 will result in a material incentive to avoid DSE2 charge (Co. Br. at 39).

The Commercial Group believes that an energy allocation of the costs in Rider DSE is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). In addition, the Commercial Group insists that the proposal to recover lost distribution revenues in the rider be rejected. Furthermore, the Commercial Group states that the opt-out provisions of the rider should include customers that have already made investments in DSM and energy efficiency programs (Com. Gr. Ex. 1 at 9).

OEC recommends that FirstEnergy's eligibility standards for relief from the rider should include: a threshold for the amount of energy savings a mercantile customer must demonstrate to be eligible for exemption; a high standard for documentation and independent review of the documentation; requirements that only projects with an avoided contribution in excess of \$10,000 would qualify for the exemption; and a requirement that the customer will not qualify for the exemption if its percentage of claimed savings is below the applicable benchmark the Companies are subject to (OEC Ex.

1 at 21-23). IEU-Ohio points out that Section 4928.66(A)(2)(c), Revised Code requires all mercantile demand-response programs, peak demand reduction programs, and all mercantile customer-sited energy efficiency programs to be included in the measurement of compliance with the statutory benchmark. Therefore, IEU-Ohio argues that OEC's recommendation to limit a mercantile customer's opportunity to commit its efficiency and peak demand reduction capabilities towards the Companies' portfolio obligations is contrary to Ohio law and the Commission's rules (IEU-Ohio Br. at 20-21).

Upon consideration of the issues raised by the various parties, the Commission believes that the Companies' proposed Rider DSE is reasonable as proposed. Accordingly, Rider DSE should be approved.

3. AMI Pilot Program and Dynamic Peak Pricing Program

The Companies state that, as part of the ESP, they will provide \$1 million toward a residential AMI pilot program and a dynamic peak pricing program to determine the potential for deployment of advanced technologies to support time-of-day pricing and other demand response and energy efficiency programs (Co. Ex. 9a at 7; Co. Ex. 4 at 16). According to the Companies, any costs incurred above \$1 million will be recovered through Rider DSE. The Companies explain that the AMI pilot will be conducted with 500 customers, at a cost of between \$500 and \$1,000 per customer for the meters and installation. The Companies intend to solicit customer participation through a direct mailing. AMI pilot participants will be subject to the dynamic peak pricing program wherein, during the summer months, the generation rates will vary based upon time-of-use periods. Participants will be encouraged to shift or decrease energy usage during peak times on non-critical days. In addition, the Companies will provide notification to the participants via e-mail, telephone, or text message the day before a critical peak day event encouraging the participants to decrease usage (Co. Ex. 9a at 23-24, Att. F).

The Companies also propose to implement a collaborative process, within 60 days after the final order in this case, in which interested stakeholders can provide input on the AMI process and the pilot program. The Companies propose a six-month process for the collaborative, after which they would evaluate the findings and they may file an AMI plan with the Commission which would include a cost recovery mechanism (Co. Ex. 9a at 23-24, Att. F).

OCC is supportive of the proposed AMI pilot program, but believes that the size of the program, 500 participants, is meager (OCC Ex. 1 at 15). Staff believes that the Companies could deploy AMI meters for a lower cost than the Companies estimated, which would allow them to deploy more than 500 meters before they reached the \$1 million threshold. Staff recommends that the Companies select the participants based on some form of stratification of the class so that the pilot sample more fully reflects the diversified makeup of the class. In addition, Staff advocates, and the Consumer Groups

agree, that any costs above the \$1 million threshold should be recovered through an AMI rider, rather than Rider DSE (Staff Ex. 2 at 3, 6; Cons. Gr. Reply Br.³ at 34).

According to Staff, the Companies are proposing that pilot participants be placed on the dynamic peak pricing rider, which provides customers prices that are more reflective of market prices. However, Staff recommends some form of critical peak pricing rebate for residential customers so that the customers would know in advance that they would pay a fixed amount for a portion of their consumption. Staff also recommends that a similar pilot be made available to commercial customers (Staff Ex. 2 at 6-7). Staff and OCC recommend that technology, such as a programmable thermostat, be offered to the participants (Staff Ex. 2 at 7; OCC Ex. 1 at 18).

OCC recommends that the Companies be required to provide tariffs that make various rate options available for the customers and that they be required to provide cost information on the billing system changes needed to accommodate wide-scale deployment of dynamic pricing. Specifically, with regard to the dynamic peak pricing program, OCC notes that the Companies are proposing only two time-of-use periods, on-peak and off-peak, along with a critical peak period. OCC recommends that the Companies add another shoulder pricing period to the program which it believes will make the program more appealing to customers and allow customers more flexibility to manage their usage (OCC Ex. 1 at 16-18).

NRDC maintains that the question posed for the AMI pilot has already been answered in other studies that have proven that summer time-of-day rates can change customer energy use behavior. Therefore, NRDC advocates that the money for the AMI pilot would be better spent after the Smart Grid study is completed if it is used to validate the savings and benefits from the deployment of Smart Grid technologies (NRDC Ex. 1 at 13).

OPAE believes that, rather than starting from the premise that smart or advanced metering systems are required to achieve customer benefits through price changes, the Companies should evaluate how to achieve peak load reduction from residential customers in the cheapest way possible. OPAE states that the cost of the proposed AMI pilot is very high and there is no basis in the ESP to justify the cost estimates for this program (OPAE Ex. 1 at 25, 27).

The Commission believes it is important that steps be taken by the electric utilities to explore and implement technologies, such as AMI, that will potentially provide benefits

³ OCC, Cleveland, NRDC, Sierra Club, NOAC, Citizen Power, and Citizens Coalition filed a joint reply brief; therefore, when referring to the arguments in this document these parties will be referred to as the Consumer Groups.

to customers in the long-run. We do not agree with NRDC that the AMI pilot program should be delayed until after the Smart Grid study is completed. Rather, we support time-differentiated and dynamic pricing based on the policies of SB 221 and as an essential component in an efficient market. We believe that a well designed AMI pilot program can represent an additional step in the right direction and should be pursued. The Staff testified that it believes that the Companies may be able to deploy AMI meters for a lower cost than they have estimated in the ESP. If this is the case, then the Commission would encourage the Companies to expand the pilot program to include additional customers. Taking note of a significant number of pilot programs showing that residential consumers will respond to time-differentiated pricing and generally find such pricing beneficial, the Companies should focus in the pilot on investigating detailed questions relating to AMI performance and how to use enabling technologies, pricing, and information to enhance the demand-response benefits from large-scale deployment of AMI. While there were other interesting proposals made by various parties regarding the AMI pilot program and the dynamic peak pricing program proposed by the Companies, the Commission suggests that these topics would best be explored as part of the collaborative process proposed by the Companies. We also encourage the Companies to fund an independent evaluation of the pilot program. Accordingly, consistent with these findings, we conclude that the Companies' AMI pilot program and the dynamic peak pricing program should be approved.

4. Economic Development and Job Retention Programs

The Companies propose to commit up to \$25 million for economic development and job retention programs (Co. Ex. 9a at 7). According to the Companies, they will provide up to \$5 million of investment each year from January 1, 2009, through December 31, 2013, for these programs and will not request recovery for these investments (Co. Ex. 9a at 26).

As discussed above, the Commission has reduced the base generation rates proposed by the Companies in order to promote the economic recovery in Ohio and has denied the proposed generation deferrals. The Commission believes that, in light of these steps and the modifications, FirstEnergy's commitment of \$25 million should be used as the first \$25 million of delta revenue contributed by the Companies under Rider DRR. With this understanding, the Commission finds that the proposed commitment of additional funds for economic development should be approved.

5. Economic Development (Rider EDR)

Pursuant to the ESP, Rider EDR would be an unavoidable rider that would promote gradualism, recognize the efficient use of electricity, and mitigate the overall bill impacts to customers through a series of credits and charges. The sum of all credits and charges in Rider EDR would be revenue neutral for the Companies and any differences would be

reconciled on an annual basis (Co. Ex. 9a at 26). According to the Companies, Rider EDR is designed for interruptible customers who are taking service as of July 31, 2008 (Co. Ex. 5 at 23). In support of the proposal that this rider be unavoidable, FirstEnergy submits that this is a social charge and, if these charges were avoidable, it would be difficult, if not impossible, for the Companies to promote and sustain this effort (Co. Ex. 4 at 9). The Companies explain that, as permitted by Section 4928.143(B)(2)(i), Revised Code, since the Companies are part of the same holding company, this rider would be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 28).

OmniSource argues that FirstEnergy has provided no justification as to why the proposed interruptible credit in Rider EDR should be limited to those loads contractually obligated to interruptible service as of July 31, 2008. According to OmniSource, the limited applicability of the credit to existing interruptible load is contrary to the concepts of gradualism and the desire to mitigate the overall bill impacts expressed by the Companies. OmniSource notes that, without the credit under Rider EDR, it will experience a disproportionately large rate increase. Therefore, OmniSource advocates that the interruptible credit be made available for new transmission voltage, interruptible load customers (OmniSource Br. at 2-4).

As discussed previously, OEG recommends that its proposed rate mitigation plan be accomplished via Rider EDR. OEG agrees that Rider EDR should be an unavoidable rider (OEG Ex. 1 at 23).

The Commercial Group believes that an energy allocation of the costs in Rider EDR is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). The Competitive Suppliers advocate that, if all customers pay for the incentives, then Rider EDR should be modified so that customers taking service from either FirstEnergy or a competitive supplier should be eligible to receive a discount in exchange for job retention, economic development, or other programs (Comp. Supp. Br. at 20).

In light of the fact that the Commission has directed the Companies to continue their existing generation rate design and tariff structure until a new revised rate design is filed with and approved by the Commission, the Commission finds that Rider EDR is unnecessary. Accordingly, the ESP should be modified to eliminate Rider EDR.

6. Energy for Education

FirstEnergy has not proposed either in the *FirstEnergy Distribution Rate Case* or in this case to renew its existing Energy for Education II electricity program, which gives public schools a discount in exchange for the prepayment of their bills, using the schools' bonding authority.

According to OSC, by adopting the rate design advocated by the Companies in the *FirstEnergy Distribution Rate Case*, the ESP completely ignores the rate impacts on the schools as a unique customer class (OSC Br. at 6). OSC argues that the elimination of school rates and the forced inclusion of the schools in the general service classes, without a proper rate adjustment to reflect the schools' actual and lower cost of service, constitute an unreasonable, undue, and unlawful prejudice and disadvantage to this customer class contrary to Ohio law (OSC Br. at 10).

OSC represents 249 public school districts that currently participate in FirstEnergy's Energy of Education II program; these school districts represent 41 percent of all public school districts in the state of Ohio. According to OSC, the Energy for Education II program provided an average of 13.4 percent discount in the schools' electric rates and saved the 249 participating school districts \$11.7 million in 2008 (OSC Ex. 1 at 2-4; OSC Ex. 2). OSC indicates that the Companies' proposal to eliminate the currently available school rates effective December 31, 2008, the proposed generation and distribution rate increases, and the proposed riders will result in severe increases in electric costs for public school customers in a manner incongruous with the schools' usage characteristics. OSC states that continuation of the Energy of Education program is critical to the education of Ohio's children and the promotion of economic development in the state. OSC points out that there is a complete record in the *FirstEnergy Distribution Rate Case* upon which the Commission can make its determination concerning the continuation of this program (OSC Ex. 1 at 6, 9). OSC recommends that approval of FirstEnergy's ESP should be conditioned upon the Companies offering the public school districts within their territory an Energy of Education III program or a school rider. According to OSC, either of these alternatives is appropriate in order to mitigate the rate increases proposed for schools and to apply the principle of gradualism (OSC Ex. 1 at 12; OSC Br. at 22-23).

As stated previously, the Commission is concerned about the elimination of the discount provided to public schools in FirstEnergy's territory. Although this has been partially addressed by the continuation of FirstEnergy's existing rate design and tariff structure, the Commission agrees that FirstEnergy should implement a new Energy for Education program which is consistent with the existing Energy for Education II program (OSC Ex. 1 at 2-4; OSC Ex. 2). Accordingly, the ESP should be modified consistent with this determination.

7. Economic Load Response Program (Rider ELR) and Optional Load Response Program (Rider OLR)

According to FirstEnergy, Rider ELR is available for customers that are currently on the Companies' existing interruptible tariffs or a special contract containing interruptible provisions which was approved before July 31, 2008. FirstEnergy explains that the terms and conditions of Rider ELR are modeled after OE's current interruptible tariffs. Rider

ELR obligates these customers to designate a contract firm load, and then be subject to interruption or required to buy power at market prices during a buy-through period. In exchange for being subject to these terms, an interruptible program credit of \$1.95 per kW/month is applied to the customer's realizable curtailable load (RCL), which is calculated by subtracting the customer's contract firm load from its average hourly demand. FirstEnergy states that the value of the interruptible program credit is based on the market value of MISO designated network resources (Co. Ex. 5 at 22).

FirstEnergy states that Rider ELR is designed to be utilized with the interruptible credit provision of Rider EDR. According to the Companies, Rider EDR is designed for interruptible customers who are taking service as of July 31, 2008. The Companies explain that these customers are currently subject to economic buy-through option events and that this concept is incorporated into Rider ELR. Conversely, Rider OLR is designed for use with new interruptible customers/load as an interruptible credit that recognizes that the customers are only subject to interruption in an emergency, and are not subject to economic buy-through option events or the interruptible credit provision of Rider EDR (Co. Ex. 5 at 23).

IEU-Ohio argues that FirstEnergy has provided no support for limiting Riders ELR to customers served under interruptible service arrangements as of July 31, 2008. Further, IEU-Ohio submits that customers served under Riders ELR and OLR should not be foreclosed from participating in any other load curtailment programs, including demand-response options available through MISO (IEU-Ohio Ex. 1 at 11).

OEG supports Rider ELR, however, OEG believes that the terms of the rider are not reasonable. Therefore, OEG recommends that Rider ELR be modified, similar to the Companies' proposal in Case No. 07-796-El-ATA, et al. (*FirstEnergy Competitive Bid Process for SSO Case*), to provide that: economic interruptions will be invoked when the day-ahead locational marginal price (LMP) exceeds 125 percent of the ESP generation rate for three consecutive hours; and economic interruptions would be limited to 1,000 hours annually. (In its brief, OEG recommended that the interruptions be limited to 250 hours annually) (OEG Ex. 1 at 28-30; OEG Br. at 22). Nucor recommends that economic interruptions be limited to 250 hours annually (Nucor Ex. 3 at 27). FirstEnergy disagrees with the suggestions to place an hour limitation on the Companies' ability to invoke the economic interruption clauses of Rider ELR. Such a limitation, according to FirstEnergy, would reduce the value of the economic interruption and would put the Companies at risk of running out of their rights to invoke the economic interruption provision at a time of high prices (Co. Ex. 19 at 7-8).

By OEG's calculations, the Rider ELR credit should be \$2.50 per kW/month, rather than \$1.95 per kW/month set forth in the ESP. Therefore, OEG submits that the

Companies should provide justification for the interruptible credit set forth in the ESP (OEG Ex. 1 at 30-31).

Nucor advocates that these riders be stand-alone interruptible rate options that are available for current, as well as new interruptible customers. Nucor proposes that Riders ELR and OLR be modified to include stand-alone emergency (mandatory) and economic (voluntary) interruption options. Nucor states that the emergency interruptible credit in Riders ELR and OLR should be \$7.50 per kW/month, and the economic interruptible credit in Riders ELR and OLR should be \$2.60 per kW/month (Nucor Ex. 3 at 19-20). OmniSource supports Nucor's proposal (OmniSource Br. at 6).

With regard to the RCL, OEG contends that the customer should receive credit for the full amount of its load that is subject to curtailment; therefore, the RCL should be computed based on the difference between a customer's on-peak load, rather than the average on-peak load as proposed by the Companies, and its firm load (OEG Ex. 1 at 30-31). Nucor recommends that the RCL be defined to reflect a customer's monthly peak demand used to calculate billing demand, instead of the customer's historical average demand during selected summer hours, as the Companies propose (Nucor Ex. 3 at 20). Further, Nucor points out that all demand charges proposed in the ESP are measured on the customer's peak, not average, demand; therefore, to be consistent with these other provisions of the ESP, the RCL should likewise be measured on the customer's peak demand (Nucor Br. at 30). However, Nucor submits that there is no record support for FirstEnergy's assertion that emergency interruptions occur at the time of peak demand; also, there is no record support, and FirstEnergy does not claim, that economic interruptions occur during the peak summer hours that FirstEnergy proposes to use to calculate the RCL. Nucor believes that FirstEnergy's proposed RCL approach will undercompensate interruptible customers (Nucor Br. at 32, 35, 37).

FirstEnergy disagrees with the proposals of OEG and Nucor, stating that the credit value developed and proposed in the ESP is based on the cost of capacity and the RCL value proposed by OEG and Nucor overstates the kW likely to be interrupted. FirstEnergy explains that a customer's peak demand is not likely to coincide with the time of an emergency interruption. Therefore, according to FirstEnergy, if the customer's peak demand, as proposed by OEG and Nucor, rather than the average hourly demand proposed in the ESP, is used to calculate the credit for Riders ELR and OLR, the Companies would be overcompensating the customer for the value of the interruption (Co. Ex. 19 at 3-6).

FirstEnergy believes that the criticisms of Riders ELR and OLR by the intervenors largely amount to requests for bigger credits. In response to these criticisms, FirstEnergy points out that, if such objectives are warranted and desirable under given circumstances,

they can be pursued through the special arrangements mechanism and do not require a change to the ESP (Co. Br. at 42).

In light of the fact that the Commission has directed the Companies to continue their existing rate design and tariff structure until a revised new rate design is filed with and approved by the Commission, we find that Riders ELR and OLR are unnecessary, at this time. Accordingly, FirstEnergy's ESP should be modified consistent with this determination.

8. Reasonable Arrangements (Rider RAR)

Pursuant to the ESP, Rider RAR would provide the mechanism to administer certain tariff discounts pursuant to Sections 4905.31 and 4905.34, Revised Code, as well as the Commission's recently adopted rules for reasonable arrangements in Chapter 4901:1-38, O.A.C. (Co. Ex. 9a at 27). FirstEnergy asserts that mechanisms, such as Rider RAR, foster job retention and promote economic development (Co. Ex. 4 at 10). To receive the benefits associated with this rider, the Companies explain that a customer would have to commit to certain energy efficiency improvements and the discounts would be forfeited if the customer switches to an alternative supplier (Co. Ex. 9a at 27).

The Competitive Suppliers advocate that, if all customers pay for the incentives, then Rider RAR should be modified so that customers taking service from either FirstEnergy or a competitive supplier should be eligible to receive a discount in exchange for job retention, economic development, or other programs (Comp. Supp. Br. at 20).

IEU-Ohio notes that Rider RAR is limited in that, if a customer is taking service under a unique arrangement or avoiding charges under Riders DSE1 or DSE2, the customer is not eligible for Rider RAR. IEU-Ohio believes that this limitation is contrary to Section 4928.66(A)(2)(c), Revised Code (Co. Ex. 9c at 75; IEU-Ohio Br. at 19).

The Commission notes that reasonable arrangements will be considered by the Commission in accordance with Chapter 4901:1-38, O.A.C. Therefore, while we acknowledge the issues raised by several parties regarding Rider RAR, we believe that our adopted rules governing reasonable arrangements take these concerns into account. Therefore, we find that Rider RAR should not be approved as proposed by the Companies and the ESP should be modified accordingly.

9. Delta Revenue Recovery (Rider DRR)

Pursuant to the ESP, Delta Revenue Recovery Rider (Rider DRR) is an unavoidable rider that would recover the difference in revenue from the application of rates in the otherwise applicable rate schedule and the result of any reasonable arrangement, governmental special contract, or unique arrangement approved by the Commission.

FirstEnergy contends that Section 4905.31, Revised Code, as amended by SB 221, permits the electric utilities to recover the revenue forgone as a result of discounts in special arrangements. FirstEnergy submits that approval of a special arrangement must also include approval of complete revenue recovery resulting from the arrangement; to do otherwise would jeopardize the financial viability of the Companies because, as stand-alone electric utilities, they have limited resources and a limited ability to absorb such lost revenue. FirstEnergy states that Rider DRR's initial charges represent the recovery of CEI's contracts that are presently in place and continue past December 31, 2008, which will only be recovered from CEI customers. With regard to new contracts, the Companies explain that, as permitted by Section 4928.143(B)(2)(i), Revised Code, since the Companies are part of the same holding company this rider will be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 27-28; Co. Ex. 4 at 11-12).

According to the Consumer Advocates, FirstEnergy did not undertake any studies or analysis to evaluate what loss of delta revenues it would take to significantly impact the energy delivery system (Con. Adv. Br. at 67). OCC points out that, prior to the ESP filing, FirstEnergy's shareholders contributed to the recovery of delta revenues. OCC recommends that the Companies be permitted to recover no more than 50 percent of the delta revenues from customers that do not have special contracts (OCC Ex. 1 at 26). Cleveland agrees that the amount of delta revenue to be recovered through this rider should be limited so as not to impose a hardship on retail customers who do not receive a discount through a special contract (Cleve. Ex. 1 at 7-8).

In the past, the Commission generally has allowed recovery of only 50 percent of the delta revenue for special contracts. Although an increase in the percentage of revenue which electric utilities recover may be warranted following the restructuring of the industry by SB 3 and SB 221, we do not believe that 100 percent recovery of the delta revenue will always be appropriate. Therefore, we find it necessary to clarify that the proportion of delta revenue to be recovered by the Companies will be determined by the Commission on a case-by-case basis when approving each individual arrangement. Therefore, we find that Rider DRR should be approved, subject to this clarification.

10. Smart Grid

The ESP provides that the Companies commit to undertake a comprehensive study of energy delivery system enhancement, including Smart Grid technologies, on or before December 31, 2009 (Co. Ex. 9a at 7, Att. E). The Companies state that they will bear the expense of this study (Co. Ex. 9a, Att. E). Upon completion of the study, the Companies will share the results with the Staff and OCC (Co. Ex. 3 at 11).

The Consumer Advocates state that FirstEnergy's proposed Smart Grid study lacks substance and a clear timeline for moving forward. The Consumer Advocates recommend

that a collaborative be established to define the appropriate goals and timelines for the study (Con. Adv. Br. at 57).

The Commission's perspective is that a Smart Grid involves the integration of the power system with an open architecture, advanced communications infrastructure. This infrastructure may provide the platform for a potentially broad range of sensing, measurement, transactional, control, and other applications that might include advanced distribution automation, equipment monitoring, dynamic retail pricing, AMI, automated demand response, distributed resource management, and electric vehicle charging systems. A Smart Grid should support new applications and enable them to interact with one another and with established power system functions.

Consistent with our conclusion on Rider DSI, the Commission believes the Companies should complete a comprehensive study of energy delivery system enhancements, including Smart Grid technologies, on an accelerated basis. The study should include planning for: Smart Grid and infrastructure enhancements, Smart Grid system architecture and interoperability requirements, and a large-scale AMI deployment.

Therefore, the Commission finds that no later than December 31, 2009, as proposed by FirstEnergy, and earlier if possible, for completion of the Smart Grid study is appropriate for such a critical issue. Furthermore, the Commission finds that FirstEnergy should work with Staff to develop a proposal to hire an independent consultant to conduct the Smart Grid study. This study should be filed with the Commission in a separate docket and a public version of this study should be made available for interested parties for review and comment. Therefore, we find that the Smart Grid proposal set forth in the ESP should be modified consistent with our decision herein.

J. Transmission

1. Transmission Rates

FirstEnergy states that the transmission rate design is now consistent with the voltage-based rate schedules set forth in the distribution rate case filing in the *FirstEnergy Distribution Rate Case*. FirstEnergy explains that the transmission rider will account for the same expenses as it did in the previous two years as set forth in Case No. 07-128-EL-ATA (*FirstEnergy 2007 Regional Transmission Organization Cost Rider Case*); with the exception that it will no longer include the amortization of the 2005 transmission expense deferral that will be recovered through the Deferred Transmission Costs Recovery Rider (Rider DTC). The Companies will continue to file in mid-October for transmission rates to be effective for January 1 through December 31 of the flowing year (Co. Ex. 5 at 25).

As the Commission stated previously, because we have retained the existing rate design and tariff structure, there is no need to change the transmission rate design.

2. Transmission and Ancillary Services (Rider TAS)

Pursuant to the ESP, the Transmission and Ancillary Services Rider (Rider TAS) would be an avoidable rider that would recover transmission and transmission-related costs, including ancillary and congestion costs and new charges imposed by FERC, a regional transmission organization (RTO), or an independent transmission systems operator (ISO) (Co. Ex. 9a at 28). This rider would be adjusted annually to reflect the costs actually incurred by the Companies' to serve the customers (Co. Ex. 9a at 6; Co. Ex. 5 at 23-24).

Staff believes that the Companies' approach is reasonable and recommends that Rider TAS be approved (Staff Br. at 17). IEU-Ohio suggests that the Staff continue to review the RTO-incurred costs to determine if the Companies are managing controllable costs so that they are prudently incurred and, to the extent an automatic recovery mechanism is allowed, FirstEnergy should be required to proactively minimize costs (IEU-Ohio Ex. 1 at 8).

The Commission finds that Rider TAS is reasonable, as proposed by the Companies, and should be approved, subject to our decision above regarding the transmission rate design. While we are approving Rider TAS, the Commission notes that, in accordance with our entry issued today in Case No. 08-1172-EL-ATA (*FirstEnergy Transmission Cost Recovery Rider Case*), the current transmission and ancillary services rider should be extended and continued until the rate design and tariff structure in the *FirstEnergy Distribution Rate Case* is approved and made effective by the Commission. The current transmission and ancillary services rider should be incorporated into the new Rider TAS, effective January 1, 2009.

K. Legacy Issues

The Companies note that the ESP provides for the recovery of certain costs from prior periods which, with the Commission's approval, were deferred for future recovery (Co. Ex. 9a at 29).

1. Deferred Distribution Cost Recovery Rider (Rider DDCRR)

Pursuant to the ESP, the Deferred Distribution Cost Recovery Rider (Rider DDCRR) would be an unavoidable rider that would recover: (1) the post May 31, 2007, unrecovered balances of distribution costs deferred in the *FirstEnergy RCP Case*; (2) the deferred distribution-related costs incurred by CEI from January 1, 2009, through April 30, 2009, equating to \$25 million; (3) the post-May 31, 2007, unrecovered balances of deferred transition taxes under the *FirstEnergy ETP Case*; and (3) the post-May 31, 2007, unrecovered balances of line extension deferrals pursuant to Case No. 01-2708-EL-COI

(*Commission Investigation of Line Extension Tariffs Case*). The Companies also propose to defer the interest on the accumulated balances, including the accumulated deferred interest, from January 1, 2009, through December 31, 2010, at .0783 percent per month (8.5 percent annually) without reduction for deferred income taxes. The Companies propose that the rider be effective on January 1, 2011 (Co. Ex. 9a at 19, 29-30, Att. G; Co. Ex. 2 at 5).

While Staff supports recovery of the types of costs contained in this rider, it believes that recovery of distribution items should be handled in distribution cases, although Staff acknowledges that the recovery requested by the Companies is permissible under SB 221. However, Staff states that, should the Commission approve this rider, the rider should be adjusted to reflect the effect of taxes and the deferred interest on accumulated balance should be net of deferred income taxes (Staff Ex. 7 at 3).

The Consumer Advocates oppose approval of these deferrals and question the breadth of the proposed deferrals. Furthermore, the Consumer Advocates note that the RCP distribution deferrals and the transition tax deferral issues are pending in the *FirstEnergy Distribution Rate Case* and, if the additional distribution charges are not approved in the *FirstEnergy Distribution Rate Case*, then the additional charges resulting from the same conceptual arguments should not be approved in the ESP (OCC Ex. 1 at 34-35; Con. Adv. Br. at 69-70).

The Commission finds that the carrying charges for the deferral balances should be adjusted for tax effects as recommended by OCC and the Staff. We agree with Staff that the calculation of the carrying charges on a net of tax basis is in accordance with sound ratemaking theory, as well as Commission precedent (Staff Ex. 7 at 3-4; *FirstEnergy Distribution Rate Case* Staff Ex. 16 at 8, 12). See also *In re Cleveland Electric Illuminating Co.*, Case No. 88-205-EL-AAM, Entry (February 17, 1988); *In re Cleveland Electric Illuminating Co.*, Case No. 92-713-EL-AAM, Entry (December 17, 1992). The stipulation in the *FirstEnergy RCP Case* did not explicitly call for the carrying charges to be calculated on a gross tax basis, and, in the absence of such explicit statement of the parties to the stipulation in the *FirstEnergy RCP Case*, our intent was for the carrying charges to be calculated on a net of tax basis in accordance with Commission precedent. Thus, Rider DDCRR should be approved as modified herein.

2. Deferred Transmission Costs Recovery (Rider DTC)

The ESP provides that Rider DTC would be an unavoidable rider that would recover certain 2005 deferred incremental transmission and related interest costs, as well as deferred ancillary service-related charges in accordance with Case Nos. 04-1931-EL-AAM and 04-1932-EL-ATA (*FirstEnergy 2004 Regional Transmission Organization Cost Rider Cases*). Rider DTC would commence January 1, 2009, and end December 31, 2010, pursuant to the ESP (Co. Ex. 9a at 30, Att. G; Co. Ex. 2 at 6; Co. Ex. 5 at 28).

The Competitive Suppliers state, and Dominion agrees, that Rider DTC should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for cost properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8; Dom. Br. at 6).

While we acknowledge the issue raised by the intervenors, the Commission finds that the proposal set forth by FirstEnergy is reasonable. Therefore, we find that Rider DTC should be approved, as proposed by FirstEnergy. While we are approving Rider DTC, the Commission notes that, in accordance with our entry issued today in the FirstEnergy Transmission Cost Recovery Rider Case, Rider DTC will not go into effect until either January 1, 2009, or the date on which the new tariffs are in effect in the FirstEnergy Distribution Rate Design Case, whichever date is later.

3. Deferred Fuel Cost Recovery (Rider DFC)

According to the Companies, they were authorized to defer and recover certain fuel costs and related interest above an established baseline, pursuant to the rate stabilization plan (RSP) in Case No. 03-2144-EL-ATA (*FirstEnergy RSP Case*), as modified by the RCP. The Companies state that Case No. 08-124-EL-ATA, et al. (*FirstEnergy Deferred Fuel Costs Case*), which is currently pending before the Commission, has been continued in order to permit the resolution of the recovery mechanism for these deferred fuel costs for 2006 and 2007 to occur in this proceeding. The Companies point out that, prior to the enactment of SB 221, the Commission allowed the current recovery of 2008 fuel expense that would have otherwise been deferred. Pursuant to the ESP, the Deferred Fuel Cost Recovery Rider (Rider DFC) would be an unavoidable rider that would recover the accumulated deferred balance of these fuel costs as of December 31, 2008, and would become effective on January 1, 2009. The aggregate estimated balance to be recovered is \$235,014,038 for 2006 and 2007, which includes \$28,202,182 of deferred interest. Based on a 25-year recovery period, the Companies state that the recovery factor would be 0.0375 cent per kWh for OE, 0.0339 cents per kWh for CEI, and 0.0260 cents per kWh for TE, which would be reconciled on an annual basis (Co. Ex. 9a at 30-31; Co. Ex. 2 at 9; Co. Ex. 5 at 18-19).

Staff proposes that the Commission adopt its recommendations set forth in its report of investigation filed in the *FirstEnergy Deferred Fuel Costs Case* (Staff Br. at 26). Consistent with its recommendation in the *FirstEnergy Deferred Fuel Costs Case*, Staff recommends that the fuel deferral contained in Rider DFC be reduced and the Companies be allowed to recover \$197,488,075 of deferred fuel for 2006-2007 (Staff Ex. 8 at 15; Staff Br. at 23-28). The Consumer Advocates support Staff's proposal to disallow recovery of certain costs (Con. Adv. Br. at 93). FirstEnergy disagrees stating that, contrary to Staff's position, the deferral of fuel costs should recognize the cost to FES to achieve the savings recognized from the purchase of the fuel and the Companies should be permitted to recover this deferral through Rider DFC. In addition, FirstEnergy argues that it should be

permitted to recover the deferrals associated with emission allowance through Rider DFC (Co. Ex. 19 at 11-14). In response to FirstEnergy's position, Staff states that FirstEnergy misunderstands the facts presented in the Staff report in the *FirstEnergy Deferred Fuel Costs Case* and, therefore, FirstEnergy's position should be rejected and Staff's proposals should be adopted (Staff Br. at 28-31).

The Competitive Suppliers state, and Dominion agrees, that Rider DFC should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for costs properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8; Dom. Br. at 6).

The Commission finds that FirstEnergy's request for recovery of the deferred fuel costs should be reduced by \$9,135,561, consistent with the recommendation of Staff (Staff Ex. 8 at 15). With this modification, the Commission finds that Rider DFC should be approved.

L. Corporate Separations Plan and Operational Support Plan

FirstEnergy submits that the Companies' corporate separation plans are in compliance with Section 4928.17, Revised Code, and Chapter 4901:1-37, O.A.C. Furthermore, the Companies offer that their operational support plan has been filed and implemented pursuant to Section 4928.31(A)(2), Revised Code (Co. Ex. 1 at 26-28).

Staff states that the Companies' generating assets have been structurally separated from the operating companies. Staff submits that, in accordance with the recently adopted corporate separation rules issued by the Commission in the *SSO Rules Case*, the Companies should file for approval of its corporate separations plan within 60 days after the rules become effective. Furthermore, Staff proposes that the Companies' corporate separations plan should be audited by an independent auditor within the first year of approval of the ESP, the audit should be funded by the Companies, but managed by Staff, and the audit should cover compliance with the Commission's rules on corporate separations (Staff Ex. 4 at 2-4).

The Commission finds that, while the ESP may move forward for approval, as noted by Staff, in accordance with our recently adopted rules in the *SSO Rules Case*, the Companies must file for approval of their corporate separations plan within 60 days after the rules become effective.

M. Significantly Excessive Earnings Test

Section 4928.143(F), Revised Code, requires that, at the end of each year of the ESP, the Commission shall consider if any adjustments provided for in the ESP:

...resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate.

FirstEnergy proposes a test for significantly excessive earnings that it believes mitigates the potential to impose asymmetric risk on the electric utilities by guarding against incorrectly determining that significantly excessive earnings have occurred. According to FirstEnergy, if asymmetric risk is imposed on the electric utilities, the electric utilities' allowed returns would have to be increased so that they could expect to earn their cost of capital on average (Co. Ex. 8 at 2, 17-18). Furthermore, FirstEnergy states that the purpose of the test is to identify significantly excessive, windfall profits (Co. Ex. 8 at 9).

In accordance with the ESP, the significantly excessive earnings test will be comprised of two parts. First, recognizing an adjustment for differences in capital structure, if the ROE for each electric utility for a year of the ESP is greater than the average ROE, plus 1.28 standard deviations above the average for a group of capital intensive industries, then significantly excessive earnings may exist for the particular electric utility, subject to the consideration of the capital requirements of future committed investments in Ohio. The group of capital intensive industries referred to by the ESP is comprised of electric utilities, natural gas utilities, oil and gas distribution companies, water utilities, environmental companies, railroads, and telecommunications service companies that have an investment-grade credit rating (Co. Ex. 9a, Att. H; Co. Ex. 8 at 10-14). Based on its analysis, FirstEnergy believes that a reasonable threshold ROE for measuring significantly excessive earning would be 19.82 percent (Co. Ex. 8 at 21).

Second, the ESP provides that the earnings in the test would be adjusted to exclude Rider DSI, subsidiary equity earnings, and any RTC or impairment write-offs that may occur subsequent to December 31, 2007. In addition, the ESP states that the equity base, for purposes of the test, would be increased by any RTC write-off or impairment write-offs that have accumulated subsequent to December 31, 2007 (Co. Ex. 9a, Att. H; Co. Ex. 2 at 7-8; Co. Ex. 1 at 23-24).

OEG submits that there are two components to determine the appropriate methodology for the significantly excessive earnings test: the significantly excessive earnings threshold and the actual earned return on common equity (OEG Ex. 2 at 23). OEG proposes that the actual earned return on common equity be computed using the per books actual earnings on common equity and the Companies' year-end actual common equity balance, with limited ratemaking adjustments. OEG believes that, for the

significantly excessive earnings test, the actual return on common equity should include: Rider DSI, off-systems sales, and prudent purchased power expenses. On the other hand, OEG believes that the following should be excluded from the actual return on common equity calculation: refunds from the previous year, the effects of fines and penalties, one-time write-offs, costs and acquisition premiums, and an accounting for derivative gains and losses. As for the Companies' proposal to exclude the after tax earnings effect on CEI's proposed write-off of RTC and extended RTC, OEG proposes that they be allowed an adjustment on a declining basis reflecting a three-year amortization of the write-off (OEG Ex. 2 at 25-28).

To identify a group of utilities and other companies that bear the same business and financial risk as the Companies, OEG identified two comparison groups, one of utilities and the other of non-utilities; adjusted the earned returns of each group to match the risks faced by the Companies (for the non-utility group the beta measure generated by Value Line was used to make the adjustment to reflect the lower risk for utility distribution service); averaged the returns to derive a base line earned level of return; and applied an adder, equivalent to FERC's 200 basis points for RTO participation and incentive investments, that describes the margin over the base line ROE that should be allowed before the earnings are considered significantly excessive (OEG Ex. 3 at 4, 7, 9). To illustrate the outcome of its methodology for computing significantly excessive earnings, OEG applied 2007 data to its methodology and derived ROEs of 12.27 percent, 13.78 percent, and 12.57 percent for TE, CEI, and OE, respectively (OEG Ex. 3 at 9). According to OEG, in 2007, the earned return of common equity for TE, CEI, and OE was 18.8 percent, 18.55 percent, and 12.51 percent, respectively. Therefore, using the threshold computed by OEG, both TE and CEI would be over the significantly excessive earnings threshold for 2007 (OEG Ex. 2 at 34).

OCC believes that FirstEnergy's comparable company methodology is arbitrary and includes no risk measures, and OCC does not believe that the reported ROE of the comparable companies should be adjusted for special or extraordinary items that affect reported earnings. According to OCC, defining significantly excessive earnings in terms of statistical significance using a 90 percent significance level, as the Companies have done, would mean that very few electric utilities would ever have significantly excessive earnings. Furthermore, OCC avers that, by applying a 1.28 standard deviation adjustment to the return on total capital, as proposed by the Companies, the threshold ROE is unnecessarily inflated. OCC proposes a seven-step procedure for the significantly excessive earnings test: (1) identify a proxy group of electric companies; (2) identify a list of business and financial risk measures; (3) establish the ranges for the proxy group for the risk factors; (4) identify a group of companies whose risk indicators fall within the ranges of the proxy group; (5) compute the benchmark ROE for comparable companies; (6) adjust the benchmark ROE for the capital structures of the Ohio electric utilities; and (7) add an ROE premium equivalent to FERC's 150 basis points ROE rider to establish the threshold

(OCC Ex. 4 at 5). Based on its analysis, OCC recommends that the threshold ROE for TE, CEI, and OE be 12.35 percent, 13.44 percent, and 12.51 percent, respectively (OCC Ex. 4 at 13-16).

Staff likewise disagrees with what it believes is a statistical methodology used by the Companies for determining what constitutes "significantly excessive" in the statute (Staff Ex. 6 at 8). Staff alleges that the Companies' approach is problematic in several respects. First, Staff believes that, under the Companies' proposal, the level of "significance" to demonstrate significantly excessive is itself excessive. Second, Staff notes that the Companies' test to determine significant has been constructed in a way counter to that required by SB 221, such that it puts the burden of proving that significantly excessive earnings have occurred on anyone claiming that the Companies have an excessive ROE, rather than the Companies as required by the statute. Staff believes that the significance test is not to show that earnings are excessive, but rather to show that they are not excessive. Thus, since the Companies own the information necessary to determine this issue, only the Companies are in a position to support a burden of proof. Third, Staff avers that the statistical definition of "significant" does not provide a useful interpretation of the legislative language. Given that the term "significantly excessive" is used several times in the statute, Staff submits that the application of the statistical definition for the word "significant" as the criterion for applying the annual test, causes the statute to have internal inconsistencies (Staff Ex. 6 at 9, 16-20; Staff Br. at 37-38).

Staff believes that the concept of "significantly excessive" is a fairness issue, rather than a statistical issue as set forth by the Companies (Staff Ex. 6 at 22). Staff maintains that, by using the wrong analytical framework, the Companies are advocating a range of values that are irrationally high (Staff Br. at 41). In order to frame a zone of reasonableness in which to apply Staff's fairness approach, Staff finds the testimony of OEG and OCC in which they refer to ROE adders such as those offered by FERC to encourage risky investment to be useful (Staff Ex. 6 at 22; OEG Ex. 3 at 9; OCC Ex. 4 at 14). With these types of considerations in mind, Staff recommends that the issue of what constitutes "significantly excessive returns on equity" in the annual earnings test be decided by implementing an adder over the average of the comparable group of between 200 and 400 basis points. According to the Staff, this method may be superior to the 1.28 standard deviation method proposed by the Companies (Staff Ex. 6 at 2, 22-24). In choosing an amount in this range, the Staff recommends that the Commission consider features, including those that serve to reduce risk or volatility, such as riders that track costs, deferrals that stabilize earnings, unavoidable charges (POLR charges), as well as the possible asymmetric risk faced by the Companies (Staff Ex. 6 at 24-25).

The Commercial Group states that the Companies' proposed earnings test is unreasonable. The Commercial Group recommends that the significantly excessive earnings test be based on whether the electric utilities are earning the approved return on

common equity. According to the Commercial Group, if the Companies' ROE is equal to or more than the Commission's approved ROE, an increase in rates and the proposed riders are not necessary and should not be permitted (Com. Gr. Ex. 1 at 18).

FirstEnergy states that the utilization by OCC, OEG, and Staff of FERC's incentive ROE adder as a measure of the cutoff over the mean of the comparable sample is completely arbitrary and attempts to use FERC's ROE adder for a purpose which it was never intended (Co. Ex. 18 at 2).

Staff recommends that the methodology for determining what comprises a comparable group for purposes of the excessive earnings test in the statute should be examined by stakeholders at a workshop or technical conference and then reported back to the Commission (Staff Ex. 6 at 2, 6). Staff states that the Companies' proposal for selecting the comparable group and calculating the ROE to be used has some good properties. However, Staff believes, and the Consumer Advocates agree, that a common methodology for the excessive earnings test should be adopted for all of the ESP cases filed at the Commission (Staff Ex. 6 at 6; Con. Adv. Br. at 95).

FirstEnergy opposes Staff's suggestion that the determination of the comparable companies and the associated ROE be postponed to a technical conference. FirstEnergy submits that the significantly excessive earnings proposal in the ESP is expressly part of the ESP and must be decided and approved herein (Co. Br. at 66-67).

The Commission believes that the determination of the appropriate methodology for the significantly excessive earnings test is extremely important. As evidenced by the extensive testimony in this case concerning the test, there are many different views concerning what is intended by the statute and what methodology should be utilized in this case. However, as pointed out by several parties, whatever the ultimate determination of what the methodology should be for the test, the test itself will not be actually applied until 2010. Therefore, the Commission agrees with Staff that it would be wise to examine the methodology for the excessive earnings test set forth in the statute within the framework of a workshop. The goal of the workshop would be for the Staff to develop a common methodology for the excessive earnings test that should be adopted for all of the electric utilities and then report back to the Commission on its findings. According, the Commission finds that Staff should convene a workshop consistent with this determination.

N. MRO v. ESP

As stated previously, contemporaneous with the filing of the ESP, the Companies also filed an application for an MRO (Co. Ex. 9a at 8). Section 4928.143(C)(1), Revised Code, provides that, if an application for an MRO is filed, then the Commission is required to approve, or modify and approve, the ESP if the ESP, including its pricing and all other

terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under the MRO.

The Companies note that the matter of generation supply beginning January 1, 2009, must be addressed in some manner because the Companies do not own generation nor do their employees currently have experience in wholesale purchases; this expertise now resides in the Companies' competitive affiliate (Co. Ex. 9a at 8). While the Companies believe that the ESP is more favorable than an MRO, they believe that, if an acceptable solution cannot be reached through an ESP mechanism, under the statute, an MRO is the alternative (Co. Ex. 9a at 8).

FirstEnergy concludes that, under the MRO proposal for full requirements service, retail customers would pay \$90.47 per MWh in 2009, \$97.56 per MWh in 2010, and \$105.49 per MWh in 2011. These prices were calculated by FirstEnergy using market data as of July 15, 2008 (Co. Ex. 6 at 2). Furthermore, FirstEnergy conducted an analysis to establish a market price benchmark for the expected cost of electricity supply for retail electric generation SSO customers in the Companies' service territory for the next three years (Co. Ex. 7 at 4). The Companies' analysis results in a market reference point for the ESP of around \$90 to \$92 per MWh over the next three years (Co. Ex. 7 at 17).

Upon review of the expected generation rates under the MRO, FirstEnergy submits that the market rate averages, net transmission costs, would be \$82.57, \$84.88, and \$88.19 per MWh for 2009, 2010, and 2011, respectively (Co. Ex. 1 at 18, Att. 1 at 1). FirstEnergy provides that the ESP generation rates, net transmission costs, would be \$67.50, \$71.50, and \$75.50 per MWh for 2009, 2010, and 2011, respectively (Co. Ex. 1, Att. 1 at 1). According to FirstEnergy, on a net present value basis, the cost of the ESP is \$1,577.1 billion and the cost of the MRO is \$2,880.5 billion. Therefore, FirstEnergy states that the ESP for the Companies in the aggregate and for each individual company is clearly more favorable for customers, and would result in a net benefit to the customers under the ESP as compared to the MRO of \$1,303.4 billion (Co. Ex. 1 at 19; Co. Ex. 1, Att. 1 at 1).

FirstEnergy maintains that Section 4928.143, Revised Code, requires that the ESP be approved if it is more favorable in the aggregate than the expected results of an MRO. According to FirstEnergy, contrary to arguments raised by various intervenors, the legal standard to approve the ESP is not: whether the rates are just and reasonable; whether the costs are prudently incurred; whether the plan provisions are cost-based; or whether each provision of the plan is more favorable than an MRO (Co. Reply Br. at 8-12).

The Companies state that, in considering the aspects of the ESP pertaining to the provision of generation service, the ESP is more favorable to customers than the MRO would be (Co. Ex. 9a at 6, 32; Co. Ex. 1 at 5). The Companies submit that, in addition to the

generation component, the ESP has other elements than, when taken in the aggregate, make the ESP considerably more favorable to customers than the MRO alternative (Co. Ex. 9a at 6). FirstEnergy points out the benefits in the ESP that are not available in the MRO, which include: price stability for both generation and distribution service; a five-year stay-out period for increasing base distribution rates; a comprehensive arrangement that settles pricing and service arrangements for the totality of electric service, not just generation; the waiver of \$591 million in RTC charges for CEI customers; a commitment to funding up to \$96 million in program costs for energy efficiency, economic development, AMI, and environmental remediation programs; substantial flexibility for the Commission to manage overall price trends; and the introduction of a performance-based rider mechanism (Co. Ex. 1 at 6, 13-15; Co. Br. at 7, 21). According to FirstEnergy, the net present value to the Companies' customers of \$1.3 billion over the plan period represents a savings averaging over \$600 per customer for the plan period (Co. Ex. 1 at 5-6, 15-18).

Staff states that, if the Commission adopts the recommendations of Staff and considers the benefits of the ESP, the Commission would find that the ESP, in the aggregate, is a better plan for customers than the MRO (Staff Ex. 5 at 10). Similarly, IEU-Ohio states that, given the uncertainty in the markets and the increase in the risk and cost of doing business for both the customers and the Companies, the ESP is the best means of satisfying the objectives of Section 4928.02, Revised Code (IEU-Ohio Br. at 11).

OEG maintains that there is an error in the Companies' analysis which compares the ESP to the MRO. OEG believes that, if this error is corrected and more current wholesale prices are used, and the market risk is addressed consistently, the ESP would be more expensive than an MRO by \$1,692.6 billion. Therefore, OEG submits that, as proposed by the Companies, the ESP is not more favorable in the aggregate than the MRO (OEG Ex. 2 at 13). However, OEG maintains that the ESP should be modified to include a least-cost portfolio of generation products, require that the POLR risk be retained by the Companies, and provide that the Companies be compensated for their prudently incurred costs. According to OEG, this modification coupled with the qualitative benefits of an ESP, such as the encouragement of new base load generation, job retention, and economic development, would, on balance, make the ESP more favorable in the aggregate than the MRO (OEG Ex. 2 at 3-4, 16). According to OEG, the effect of using the more recent September 2008 forward prices versus the July 2008 forward prices used by the Companies in their calculation is that the ESP benefit computed by the Companies has been reduced. Therefore, OEG notes that, based on September 19, 2008, forward prices, the wholesale market price to serve the Companies' load would be \$63.45, \$65.23, and \$66.15 per MWh, for 2009, 2010, and 2011, respectively; compared to FES's offer price proposed in the ESP of \$75, \$80, and \$85 per MWh, respectively, for the same years (OEG Ex. 2 at 4, 11). Furthermore, OEG points out that FirstEnergy includes all wholesale generation prices and all retail risk premiums in computing the MRO wholesale supplier market prices that it uses to compare the MRO to the ESP; however, FirstEnergy's ESP computation only

includes the wholesale generation prices. In addition, OEG indicates that FirstEnergy's comparison computation does not include additional items in the ESP cost, such as fuel transportation surcharges, costs for alternative energy/renewable requirements, cost for new taxes or environmental requirements, increased fuel expenses in 2011 and capacity purchases, and the proposed Rider MDS (OEG Ex. 2 at 12).

Based on data from July 15, 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the more realistic forward market prices would be \$55.65, \$54.78, and \$53.87 per MWh for 2009, 2010, and 2011, respectively (OCC Ex. 3 at 12; Con. Adv. Br. at 12). The Consumer Advocates argue that FirstEnergy's proposed ESP is less favorable than the alternative. According to the Consumer Advocates, the ESP would need to be significantly modified before it could be considered more favorable than the alternative (Con. Adv. Br. at 96, 99). OMA, OEC, Material Sciences, and the Commercial Group agree that FirstEnergy has failed to meet its burden of proof under the statute that the proposed ESP, in the aggregate, is more favorable than an MRO (OMA Br. at 6; OEC Br. at 4; Mat. Sci. Br. at 5; Com. Gr. Br. at 3). Similarly, OHA contends that the proposed ESP fails to mitigate the harmful effects of the new regulatory assets, the proposed deferrals, and the effects the rate increases will have on hospitals and, therefore, the ESP does not provide benefits that make it more favorable than a simple MRO (OHA Br. at 7).

The Competitive Suppliers submit that the ESP is not more favorable, in the aggregate, than the MRO. The Competitive Suppliers cite five reasons supporting their view that FirstEnergy has not demonstrated that the ESP is more favorable than the MRO. First, they point out that the July 2008 forward electricity prices used by the Companies in support of the ESP are out of date and the current forward prices are now lower. Second, the Competitive Suppliers believe that the Companies' quantitative comparison of between the MRO and ESP is materially flawed in that it was not done on an apples-to-apples basis and it uses an incorrect risk premium basis. Third, the suppliers opine that, when the Companies' analysis is adjusted to take into consideration the first and second errors stated above, the claimed benefit of the ESP in the aggregate is eliminated and the ESP is actually \$200 to \$840 million more expensive than the MRO. Fourth, the suppliers contend that the ESP structure would be highly adverse to retail competition, pointing out that the net result of Riders DGC, MDS, SBC, and NDU is that the shopping credit is reduced and customers will have an economic disincentive to switch to a competitive provider. Finally, the Competitive Suppliers state that there are fundamental differences between the MRO and ESP regarding the risk that will be borne by the Companies, the suppliers, and the customers and, because of these differences, on the basis of the MRO and ESP commodity price comparisons, it can not be concluded that the contract in the ESP between the Companies and FES is fairly priced (Comp. Supp. Ex. 1 at 5, 8 and Ex. 2 at 3-4, 6). Dominion agrees with the analysis of the Competitive Suppliers, stating that the

proposed ESP would be more expensive for customers than a properly structured MRO (Dom. Br. at 4).

Contrary to the position taken by OEG, FirstEnergy contends that the market price analysis supplied in support of the ESP does not need to be updated in order for the Commission to determine whether the ESP is more favorable than the expected result of the MRO. Furthermore, FirstEnergy states that the use of more recent market forwards cannot be done in a vacuum and must be considered along with credit market conditions, regulatory rulings, and increased risk premiums, all of which will have the effect of increasing expected MRO prices (Co. Br. at 20).

Staff offers that, if the current market rates are indicative of the prices that would occur during the term of the ESP, then it may be appropriate to lower the generation rates. However, Staff believes that the current low prices may not last. Therefore, Staff recommends that, if the rate is lowered from the proposal set forth by FirstEnergy, perhaps an annual or semi-annual true-up mechanism might be the best choice to correct the price charged so that it reflects the actual cost of power acquisition. Staff proposes that this adjustment be in lieu of the deferrals suggested by the Companies and that the rates could be adjusted either up or down, but no higher than the generation rates proposed by the Companies (Staff Br. at 8-9).

Upon consideration of the application in this case and the provisions of Section 4928.143(C)(1), Revised Code, the Commission finds that the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, as modified by this order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

III. CONCLUSION

Upon review of FirstEnergy's ESP application, taking in consideration the requirements established by SB 221, the Commission finds that the proposed ESP should be approved with the modifications set forth in this order.

Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this order by December 29, 2008. In light of the short timeframe remaining before these tariffs by necessity must go into effect, the Commission finds that the revised tariffs shall be approved effective January 1, 2009, contingent upon final review and approval by the Commission.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

- (1) The Companies are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.
- (2) On July 31, 2008, FirstEnergy filed an application for an SSO in accordance with Section 4928.141, Revised Code.
- (3) On August 18, 2008, a technical conference was held regarding FirstEnergy's application and on August 25, 2008, a prehearing conference was held in this matter.
- (4) On September 15, 2008, and December 16, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OP&E; Nucor; NOAC; Constellation; Dominion; OHA; Citizens' Coalition; NRDC; Sierra Club; NEMA; Integrys; Direct Energy; city of Akron; OMA; FPL; Cleveland; NOPEC; OFBF; American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens; OmniSource; Material Sciences; OSC; COSE; Morgan Stanley Capital Group; Commercial Group; and OASBO/OSBA/BASA.
- (5) The hearing in this proceeding commenced on October 16, 2008, and concluded on October 31, 2008. Eight witnesses testified on behalf of FirstEnergy, 21 witnesses testified on behalf of various intervenors, and nine witnesses testified on behalf of the Staff.
- (6) Nine local hearings were held in this matter at which 106 witnesses testified.
- (7) Briefs and reply briefs were filed on November 21, 2008, and December 12, 2008, respectively.
- (8) The Companies' application was filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.
- (9) The average base generation rates for the ESP, as modified and approved by the Commission are \$0.0675 per kWh for 2009, \$0.0695 per kWh for 2010, and \$0.071 per kWh for 2011.

- (10) The proposed ESP, as modified by this order, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

ORDER:

It is, therefore,

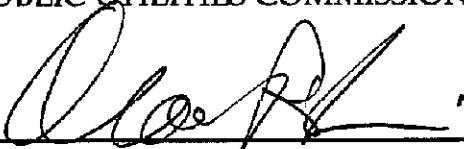
ORDERED, That the application of FirstEnergy for approval of an ESP, pursuant to Sections 4928.141 and 4928.143, Revised Code, be modified and approved, to the extent set forth herein. It is, further,


ORDERED, That the Companies' shall file revised tariffs consistent with this order by December 29, 2008, and that the revised tariffs shall be approved effective January 1, 2009, contingent upon final review and approval by the Commission. It is, further,

ORDERED, That the Companies shall notify their customers of the changes to the tariff via bill message or bill insert within 30 days of the effective date of the tariff. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further,

ORDERED, That a copy of this opinion and order be served on all 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

CMTP/GAP/vrm

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DEC 19 2008



Renee J. Jenkins
Secretary