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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 a Standard Service Offer Pursuant to Section 4928.143, Revised Code in the Form of an Electric Security Plan	))))))	Case No. 08-935-EL-SSO

INITIAL BRIEF OF NUCOR STEEL MARION, INC.

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TABLE OF CONTENTS

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In accordance with the Hearing Examiner's instruction at the hearing in the above-captioned proceeding, Nucor Steel Marion, Inc. ("Nucor") hereby submits its initial brief addressing the electric security plan ("ESP") proposed by the Ohio Edison Company ("Ohio Edison"), the Cleveland Electric Illuminating Company, and the Toledo Edison Company ("Toledo Edison") (collectively "FirstEnergy").

I. INTRODUCTION

Nucor is a large industrial, interruptible customer of FirstEnergy that consumes millions of dollars worth of electricity each year. Nucor recycles steel scrap by using electricity to melt the scrap and produce new steel. Nucor Corporation (of which Nucor Steel Marion, Inc. is an affiliate) is North America's largest recycler of any material, recycling over 20 million tons of scrap steel in 2007 and conserving considerable amounts of iron, limestone, and coal that would otherwise be used to produce steel.

Nucor has actively and fully participated in this proceeding in order to respond to the massive potential rate increase FirstEnergy has proposed to Nucor that is potentially in excess of 50% for 2009, plus additional increases in 2010 and 2011. Such an increase to individual customers is unconscionable, particularly when the average increase is expected to be roughly 5% in the first year to all customers. Given the highly competitive nature of the steel industry and the negative impacts of today's economic climate, the proposed increases would be crushing on Nucor and the rest of Ohio industry located in areas served by FirstEnergy. Nucor's recommendations, if adopted and implemented, would mitigate the proposed increases while maintaining reasonable rates for all customers.

A. Summary of Nucor Recommendations

FirstEnergy has not met its burden of proof to show that the proposals contained in the ESP are just and reasonable and consistent with the policy of the state. Nucor recommends that the ESP as proposed by FirstEnergy should not be approved by the Commission. Instead, the ESP should be modified as recommended by Nucor and others as indicated in this brief. Nucor's positions and recommendations on the ESP proposal are summarized below:

- Cost Assignment Among Customer Classes
    - FirstEnergy's proposed near-uniform volumetric rates (the rates vary based on voltage to reflect losses) do not take into account load factor and other cost causation differences between customer classes. As a result, customer classes with higher load factors will bear a disproportionate and excessive share of generation costs under the ESP.
    - FirstEnergy should be required to apply the class allocation factors ("CAFs") proposed by FirstEnergy in its 2007 competitive bidding proposal in Case No. 07-796-EL-ATA ("CBP proposal") to the proposed ESP generation rates to develop class-specific generation rates.

- In conjunction with the CAF proposal, the Commission should apply gradualism principles and limit the rate increase to any customer class to no greater than two times the retail average increase.

- As an alternative to the CAF approach, FirstEnergy should retain all of its existing firm and interruptible rate schedules and apply a uniform percentage adder to the generation portion of each existing rate schedule in order to preserve the existing rate relationships.

- Interruptible Rates

  - Properly designed interruptible rates provide numerous reliability and economic benefits to the system and are an important tool for job retention and economic development. While interruptible rates have long provided such benefits, the need to retain existing interruptible load and to expand participation on interruptible rates is even more critical today given the peak demand reduction requirements of Amended Substitute Senate Bill No. 221 and today's economic conditions. FirstEnergy's interruptible riders as proposed, however, would under-compensate interruptible customers for the benefits they provide and would discourage participation on the rates.

  - The following changes should be made to FirstEnergy's proposed interruptible rates (Riders ELR and OLR):

    - A customer's Realizable Curtailable Load ("RCL"), used to determine the customer's credit for interruptible load, should be equal to the customer's monthly peak billing demand minus the customer's firm load – not the customer's average historical demand from peak periods from previous summer months minus firm load, as proposed by FirstEnergy.

    - Emergency and economic interruptible programs are separate products and should be separate programs with separate credits, and customers should have the option in participating in one or both programs.

    - The credit for emergency interruptions should be set no lower than $7.50/kw/month, which reflects a reasonable (though conservative) estimate of the long-run avoided cost of new generation capacity displaced by interruptible load.

    - The credit for economic interruptions should be set no lower than $2.60/kw/month.

    - A reasonable limit on the number of hours in which FirstEnergy may call economic interruptions should be established, such as 250 hours. The trigger for economic interruptions should be when LMPs are 125% above the applicable kWh net charges in Riders GEN for three consecutive hours (as originally proposed by FirstEnergy in the CBP case).

- FirstEnergy's proposed time-of-day rates should be modified to split the 16-hour summer weekday peak period into two separate pricing periods (a peak and super-peak period).

- FirstEnergy's proposed Minimum Default Service charge is not cost-based and is an impediment to retail competition and should be eliminated.

- The generation rates proposed by FirstEnergy are excessive and should be significantly reduced.

- FirstEnergy's proposed Capacity Cost Adjustment Rider should not apply to interruptible load.

- If an ESP is not approved and in place by January 1, 2009, the Commission should direct FirstEnergy to retain its current rates as is standard service offer in accordance with the requirements of Section 4928.143(C)(2)(b) of the Revised Code.

B. Overview and Background on FirstEnergy ESP Proposal

2008 has been a watershed year for the electric utility industry in Ohio. On May 1, 2008, Governor Strickland signed Amended Substitute Senate Bill No. 221 ("SB 221") into law. The new law made significant changes to the standard service offer ("SSO") requirements for electric utilities. SB 221 requires utilities to have an SSO in place by January 1, 2009. Section 4928.141(A), Revised Code. The SSO may take the form of an ESP, or a market-rate offer ("MRO"). *Id.* Importantly, the statute requires that if a utility's ESP or MRO is not approved by January 1, 2009, the utility's existing rates will continue as the utility's SSO until an ESP or MRO is approved. *Id.* In order to win approval for an ESP proposal, a utility must demonstrate that the ESP is "more favorable in the aggregate as compared to the expected results that would otherwise apply" under an MRO. Section 4928.143(C)(1), Revised Code. Pursuant to the proposed rules implementing SB 221 issued by the Commission,[1] "the burden of proof to show that the proposals in [an ESP or MRO] application are just and reasonable and are consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code shall be upon the electric utility." Proposed Rule 4901:1-35-06.

On July 31, 2008, the day SB 221 became effective, FirstEnergy filed applications requesting approval of both an MRO and an ESP. The MRO application was set for hearing in Case No. 08-936-EL-SSO, and the hearing was held in that proceeding from September 16, 2008 through September 22, 2008 before Attorney Examiners Gregory Price and Christine Pirik. In the MRO proceeding, Nucor sponsored expert witness testimony of Dr. Dennis W. Goins, actively participated in the hearing, and filed initial and reply briefs. The hearing considering the ESP application ("Application") occurred between October 16, 2008 and October 31, 2008 before Attorney Examiners Price and Pirik.

Under FirstEnergy's ESP proposal, FirstEnergy would provide a three-year standard service generation offer of 7.5 cents per kWh in 2009, 8.0 cents per kWh in 2019, and 8.5 cents per kWh in 2011. FirstEnergy also proposes to defer for future recovery approximately 10% of the generation price each year, and that FirstEnergy be allowed to securitize the deferred costs. As is the case today, FirstEnergy would obtain wholesale power to serve its SSO load from its generation affiliate, FirstEnergy Solutions

[1] *See* Case No. 08-777-EL-ORD. On September 17, 2008, the Commission issued a finding and order adopting new rules concerning standard service offer, corporate separation, reasonable arrangements, and transmission riders for electric utilities pursuant to Sections 4928.14, 4928.17, and 4905.31 of the Revised Code. On November 5, 2008, the Commission issued an entry granting rehearing of the proposed rules for further consideration.

("FES"). The plan would also establish distribution rates for the three year term of the ESP, and would allow for the recovery of transmission and transmission-related costs through a rider similar to the existing transmission rider. In addition to the provision of generation, distribution, and transmission service, under the proposed ESP FirstEnergy commits to make certain investments to improve its distribution system and to establish energy efficiency, demand response, and economic development and job retention programs.

FirstEnergy states that increases in total customer rates under the ESP – including generation, transmission and distribution – would be moderated to an average of 5.32% in 2009, 4.01% in 2010 and 5.99% in 2011. Application at 5. On the surface, this level of increase appears relatively modest compared to the fears of some over the impact of a new regime of electric supply. As the saying goes, however, the devil is in the details. In actuality, many FirstEnergy customers (large industrial interruptible customers such as Nucor in particular) will see rate increases far in excess of the average increases cited by FirstEnergy. Nucor, for example, expects to see a rate increase in excess of 50%, and some industrial customers may experience even larger rate increases. If approved in its current form, therefore, the ESP could have disastrous consequences for job retention and economic development in Ohio, particularly at a time when the country is facing extreme economic conditions and the very real possibility of an extended recession.

Indeed, the principal saving grace to the ESP proposal in comparison to the MRO is FirstEnergy's decision in the ESP, unlike the MRO, to offer interruptible, time-of-use and economic development rates. However, FirstEnergy should not be able to justify an ESP over an MRO on the basis of rate design. As Nucor contended in the MRO proceeding, there is no reason for excluding similar rate design components from the MRO. Yet even with these crucial rate design elements in the ESP, it still fails to maintain reasonable rates, particularly for industry.

The dramatic rate increases that would be imposed on industrial customers are largely driven by FirstEnergy's proposed cost allocation and rate design proposals. FirstEnergy should be required to correct the flaws in its proposed cost allocation/assignment and rate design as a prerequisite for Commission approval of the ESP. Consistent with Section 4928.143(C)(1) of the Revised Code, the Commission should reject, or modify and approve, FirstEnergy's ESP, and direct FirstEnergy to adopt the recommendations summarized in section I.A. above and discussed in detail below. These recommendations are fully supported by the evidence on the record in this proceeding, including the comprehensive testimony of Nucor's expert witness, Dr. Dennis W. Goins.

II. FIRSTENERGY'S RATES SHOULD REFLECT CLASS-SPECIFIC COST DIFFERENCES.

FirstEnergy's proposed class cost allocation/assignment and rate design is the key factor underlying the dramatic rate increases for large industrial customers under the ESP. Nucor believes that this fixing this issue is crucial to reasonable rates for industrial and other high load factor customers. FirstEnergy proposes to consolidate over twenty existing rate schedules into eight new rate classes, consistent with the rate classes FirstEnergy proposed in its distribution rate case. Direct Testimony of Gregory F. Hussing, FirstEnergy Exhibit 4 ("FirstEnergy Ex. 4") at 3, 5. FirstEnergy then proposes to apply a near-uniform (differentiated on the basis of a loss adjustment) generation rate to the eight rate classes. As discussed in detail below, FirstEnergy's proposed rate design recognizes almost no cost differences to serve customer classes based on the particular characteristics of those classes. The result is an over-allocation of costs to customers in the general service – transmission ("GT") class (as well as certain other classes), and a dramatic increase in rates for such customers.

The rate impacts on industrial customers would be significantly mitigated if the rates are adjusted to reflect the cost differences, in particular the differences based on class load factor, to serve the various customer classes. The evidence on the record in this case overwhelmingly supports changes to the cost allocation and rate design to recognize class cost differences.

As a result, Nucor urges the Commission to adopt Dr. Goins' recommendation to use the Class Allocation Factors proposed by FirstEnergy in the 2007 CBP case to address this issue. The Commission should also adopt the recommendation of Ohio Energy Group ("OEG") witness Stephen Baron to establish limits on class rate increases for gradualism purposes. If the Commission elects not to adopt both of these proposals, then Nucor submits that the only reasonable alternative would be to retain all of the existing rate schedules and simply apply any percentage generation increase to the generation components of those rates.

A. Description of FirstEnergy's Proposed Rider GEN

Rider GEN contains eight rate classes: residential service (Rate RS), general service – secondary (Rate GS), general service – primary (Rate GP), general service – subtransmission (Rate GSU), general service – transmission (Rate GT), street lighting service (Rate STL), traffic lighting (Rate TRF), and private outdoor lighting service (Rate POL). Application, Vol. 2a, Schedule 3a at 68. To develop the proposed generation rates, FirstEnergy adjusted the total generation rate by voltage level to account for distribution losses. Direct Testimony of Kevin T. Warvell, FirstEnergy Exhibit 5 ("FirstEnergy Ex. 5") at 9. As explained by Nucor witness Dr. Goins, with the exception of these voltage differentials, "the ESP generation rates make no effort to recognize cost differences to serve specific classes (for example, loads characterized by timing, duration, and load factor differences)." Direct Testimony of Dennis W. Goins, Nucor Exhibit 3 ("Nucor Ex. 3") at 10-11.

Rider GEN breaks the generation rate into summer and winter period rates, and provides for a time-of-day rate option that further breaks the summer and winter period rates into on-peak and off-peak rates. Application, Schedule 3a, Proposed Original Sheet 88. FirstEnergy's proposes volumetric generation rates that are near-uniform across the eight customer classes in Rider GEN:

Rate Class	**Summer (cents/kwh)**	**Winter (cents/kwh)**
RS (First 500 kWh)	8.0987	7.3474
RS (kWh in excess of 500)	9.0987	7.3474
GS	8.5737	7.3474
GP	8.2760	7.0923
GSU	8.0429	6.8926
GT	8.0353	6.8861
STL	8.5737	7.3474
TRF	8.5737	7.3474
POL	8.5737	7.3474

B. Large Industrial Customers Will Receive Disproportionate Rate Increases Under FirstEnergy's Proposed Rate Design.

1. Industrial customers will receive enormous rate increases on both an inter-class basis and on an intra-class basis.

Under the rate design in the ESP, large industrial customers on Rate GT will receive rate increases far in excess of the 5% average increase FirstEnergy touts in the Application. The rate impact analysis sponsored by FirstEnergy witness Mr. Hussing bears this out, showing the class rate increases:

Table 1. Proposed ESP Rate Increases (%): 2009

	FirstEnergy Company		
Class	**OE**	**CEI**	**TE**
RS	2.38	6.17	5.73
GS	2.53	4.77	(6.92)
GP	5.33	2.23	(10.27)
GSU	8.69	1.74	(14.88)
GT	19.63	13.50	33.83
POL	2.46	26.29	16.17
STL	11.53	17.20	1.92
TRF	12.38	21.33	(25.66)
Total	5.23	5.26	6.96

Source: FirstEnergy ESP, Schedule 1A; CEI Contracts excluded

The rate impacts get more severe for Rate GT customers in the later years of the ESP. FirstEnergy's rate impact analysis shows an additional 5.33% increase over the 2009 rates for Ohio Edision customers on Rate GT in 2010, and an additional 7.2% increase for those customers in 2011. Tr. Vol. V at 71. Looking at the three years in total and assuming that the ESP remains in effect for all three years, Ohio Edison Rate GT customers would experience an average rate increase of 35%. *Id.* at 72. Toledo Edison Rate GT customers would see even more severe impacts – rate increases of 33.83% in

2009, 5.54% in 2010, and 7.51% in 2011. Application, Vol. 1b, Schedules 1a, 1b, and 1c.

As demonstrated above, the rate impacts on Rate GT customers will be severe on an inter-class basis (*i.e.*, when the Rate GT class is compared to the other proposed customer classes). However, the rate impact on some customers will be far more severe, when the impact intra-class is also considered (*i.e.*, the impacts on customers within a class when compared to other customers within the same class). Proposed Rate GT is comprised of customers that are on current rate schedules that will be eliminated under FirstEnergy's rate design. Mr. Hussing testified that the Ohio Edison Rate GT would include customers on current rate schedules 21, 23, 28, and 29. Tr. Vol. 5 at 68, 70. Since the rates under these existing schedules vary, the rate impacts will vary. (For example, part of Nucor's load is served on Rate 29 and Nucor is intimately familiar with the potential impact on its costs.) Unfortunately, from the standpoint of the record, the rate impacts on individual customers are not readily apparent from FirstEnergy's rate impact analysis because FirstEnergy chose to display the rate impacts only on a class basis. *See, infra,* Section II.B.2.

Although the rate impact analysis contained in the Application effectively disguises the most severe impacts that would be experienced under the ESP proposal, evidence on the record in this case clearly demonstrates that some FirstEnergy customers, such as Nucor, will be facing rate increases far in excess of 19.63% in 2009. The increases for high load factor customers and customers on interruptible rates will be particularly severe. *See* Nucor Ex. 3 at 9; Nucor Exhibit 3A (stating that customers currently on Rate 29 will see rate increases in excess of 50%); Direct Testimony of Kevin

C. Higgins, Kroger Exhibit 1 ("Kroger Ex. 1") at 10 (noting that some high load factor Rate GP customers will experience rate increases of 38% in the summer and 23% in the winter, while some low load factor Rate GP customers will experience rate decreases in both seasons). Indeed, on cross-examination, FirstEnergy witness Mr. Hussing agreed that some customers could see rate increases in excess of 100%. Tr. Vol. IV at 216.

2. FirstEnergy's efforts to promote gradualism are necessary, but far from sufficient, to mitigate the proposed rate increases for large industrial customers.

FirstEnergy argues that "gradualism" is a key consideration of its rate design. According to Mr. Hussing, "[t]he transition from historic rate levels and structures to proposed rates must be accomplished through a reasoned and gradual approach in order to accomplish the objective of mitigating significant customer impacts." FirstEnergy Ex. 4 at 5. Nucor agrees with FirstEnergy that gradualism is a key rate design concept. However, as the discussion above shows, FirstEnergy's application of gradualism is haphazard at best, and does not go nearly far enough to mitigate the enormous rate increases faced by large industrial customers.

According to Mr. Hussing, gradualism is a vague concept that can be applied in many different ways. Tr. Vol. V at 66. For instance, Mr. Hussing testified that gradualism could be applied on an intra-class basis, even though he applied it only on an inter-class basis. *Id.* Mr. Hussing testified that, as part of his gradualism analysis, he performed no analysis based on existing rate schedules, and that he performed no analysis of rate impacts on individual customers. Tr. Vol. V. at 67; Tr. Vol. IV at 216.

Applying gradualism on an inter-class basis only, as FirstEnergy did, only serves to cast the ESP proposal in a better light and to mask the rate impacts that will be experienced by customers under the ESP. It is important to remember that the eight rate classes FirstEnergy proposes in its ESP do not exist today – rather, FirstEnergy's customers are on one or more of the current rate schedules that FirstEnergy proposes to eliminate. Herding existing customers into one of the new rate classes, calculating an average rate from all the rate schedules that comprise the new rate class, then calculating the rate impacts for the new rate class under the ESP proposal does not tell us the whole story about the rate impacts on individual customers or rate schedules.

Similarly, a concept of gradualism that looks at rate impacts only based on the new rate classes while ignoring the impacts on existing rate schedules results in widely disparate rate impacts for individual customers. FirstEnergy proposes to implement the gradualism principle through the generation deferral and Rider EDR. Tr. Vol. V at 38-39. The rate impacts discussed above reflect both of these features, which clearly shows that the mitigation FirstEnergy proposes in order to implement gradualism is far from adequate, particularly for high load factor and interruptible customers.

C. The Lack of Recognition of Class-Specific Cost Differences in FirstEnergy's Proposed Rates Underlies the Massive Rate Increases for Large Industrial Customers.

As noted above, the generation rates in Rider GEN are nearly uniform across the eight proposed customer classes. As Dr. Goins testified, the primary reason for the disproportionate rate increase for Rate GT customers is FirstEnergy's failure to recognize the varying cost of generation capacity by customer class in developing the ESP rates. Nucor Ex. 3 at 10.

1. The cost of capacity and energy to serve high load factor customers is lower than the cost to serve lower load factor customers.

The average cost of capacity and energy to meet class-specific loads is lower for classes with higher load factors and classes with primarily off-peak usage. Nucor Ex. 3 at 11. As Dr. Goins explains:

> This inference is the same whether one looks at the issue in the context of a traditional cost-of-service study or an analysis of competitively priced generation products. The reason is simple – the fixed cost of capacity to serve higher load factor customers is spread over more kWh, resulting in a lower average cost. Moreover, with respect to off-peak loads, capacity costs to serve such loads approach zero, again resulting in a low average cost of generation products for off-peak customers.

Nucor Ex. 3 at 11-12.[2] In allocating costs and setting rates, it is standard practice for this Commission and other regulatory commissions to recognize in rates the lower average cost of generation and transmission so serve higher load factor classes compared to lower load factor classes, and the lower cost of serving off-peak consumption relative to on-peak consumption. *Id.* at 12. Unfortunately, unlike its 2007 CBP case, FirstEnergy does not propose do so in this case.

2. FirstEnergy's own testimony in this proceeding recognizes that generation costs vary by customer class.

FirstEnergy's own testimony on projected prices under an MRO recognizes that the cost of generation varies by class or type of customer, although it ignores this fact

[2] At the hearing, a hypothetical demonstrating the effect of load factor on rates to recover the fixed cost of capacity was discussed with Mr. Warvell. The hypothetical assumed a supplier with $1,000 of fixed costs and two customers – Customer A with a 10% load factor and Customer B with a 20% load factor. Customer A would use 73 kWhs a month (10% times the number of hours in the month) for every kW of demand, and Customer B would use 146 kWhs a month (20% times the number of hours in the month) for every kW of demand. To recover its fixed cost from Customer A on a per kWh basis, the supplier would charge $13.70 per kWh ($1,000 divided by 73). To recover its fixed cost from Customer B on a per kWh basis, the supplier would charge $6.85 per kWh ($1,000 divided by 146). The supplier would have to charge the lower load factor customer a per kWh charge twice as high as the per kWh charge to the higher load factor customer to recover its fixed costs. Tr. Vol. II at 93-95.

when it comes to cost allocation and rate design under the ESP. The analysis and testimony of FirstEnergy witness Dr. Scott Jones shows that capacity costs create a substantial generation rate differential among customer classes based on class load factors. For example, for 2009, Dr. Jones calculated a capacity cost of $4.40 per MWh for industrial customers, compared to $5.60 per MWh for commercial customers and $8.18 per MWh for residential customers. Direct Testimony of Scott T. Jones, FirstEnergy Exhibit 6 ("FirstEnergy Ex. 6") at 13, Exhibit 4. Dr. Jones used a very low capacity cost of $2.20 per kW month, which he was told was taken from a bilateral contract for designated network resources ("DNR") in Midwest ISO. FirstEnergy Ex. 6 at 12-13; Tr. Vol. III at 91. Dr. Jones recognized that there is substantial uncertainty regarding expected future prices of capacity, and he acknowledges that capacity costs may trend upward over the next several years. FirstEnergy Ex. 6 at 12-13.

In fact, in the case of an ESP generation offer (which is not a market-based offer), Dr. Jones' capacity value is far understated. Dr. Jones' capacity value apparently represents an estimate of the capacity costs that an MRO supplier would incur to meet the Midwest ISO capacity requirement. Tr. Vol. III at 89. It is not based on a cost of service study – in other words, it does not reflect the actual capacity or fixed costs of the generation plant that would be used by FES to generate the kilowatt hours under the ESP. As Mr. Warvell conceded on cross examination, FirstEnergy elected to offer no generation cost of service study in this case. Tr. Vol. II at 88. Mr. Warvell could not provide information as to the actual capacity costs associated with the extensive generation resources that FES would make available to supply Ohio load. *Id.* at 85, 88. In addition, as discussed further below, the cost of capacity Dr. Jones uses in his analysis is well below the cost of capacity Dr. Goins used in his analysis, and is also lower than the capacity value used by FirstEnergy's other MRO cost witness, Mr. Graves. *See, infra,* sections III.E.1 and III.E.2.b.

At the hearing, Dr. Jones agreed that greater the cost of capacity, the greater the capacity cost differential between customer classes. Tr. Vol. III at 96-97. If Dr. Goins' or Mr. Graves' capacity value was used instead of Dr. Jones' value, therefore, the cost differential between the customer classes would be even greater than that reflected in Dr. Jones' analysis.

In addition to capacity cost differences among customer classes, Dr. Jones also recognizes that a market supplier's costs will vary based on load shape. FirstEnergy Ex. 6 at 8-9. As Dr. Jones explains, customers do not use electricity at a constant rate throughout the year, and market prices for power vary throughout the day. *Id.* Dr. Jones calculated a load-shaping cost for each customer class. *Id.* at 9. As his analysis demonstrates, the load shaping costs for the industrial customer class is significantly lower than for the residential and commercial classes. *Id.* at Ex. 3.

3. FirstEnergy has recognized class cost differences in both cost-of-service and market-based rate proposals.

FirstEnergy's existing rates and its 2007 CBP proposal demonstrate Dr. Goins' point that the practice of reflecting cost differences in rates is applicable regardless of whether rates are set on a cost-of-service basis or through a competitive solicitation.

Currently, FirstEnergy buys capacity and energy from its generation affiliate, FES. This is no different than what FirstEnergy proposes to do again under its ESP. The existing rates were set on a cost of service basis, and costs differences between customer classes are reflected in FirstEnergy's current rates. There is no reason that the same approach should not apply to ESP rates.

Under FirstEnergy's 2007 CBP proposal, FirstEnergy proposed to acquire SSO generation supply through a competitive bid. Nevertheless, under both of the options contained in that proposal, class cost differences were reflected in the rates. Under the "load class" approach, cost differences would be reflected in rates because suppliers would bid to serve a particular load class. The suppliers' costs, and the resulting rates, would vary based on the characteristics of the load class. Nucor Ex. 3, Ex. DWG-2. Similarly, under the "slice of system" approach proposed in that case (the approach most similar to what is being proposed in this case), FirstEnergy proposed to recognize class cost differences in its retail rates by proposing class allocation factors based on the historical rate relationships that resulted in different generation rates for different customer classes. Nucor Ex. 3, Ex. DWG-3.

In sum, regardless of whether FirstEnergy's ESP proposal is a traditional cost-of-service proposal or a market-based proposal, or some hybrid, the rates between the classes should reflect cost of service differentials. There is no evidence on the record in this proceeding demonstrating why it would be unreasonable or inappropriate to reflect cost differences among customer classes. By contrast, there is extensive evidence on the record that such cost differences undoubtedly exist, and that such differences should be recognized in rates regardless of whether rates are cost based, market based, or something in between. Moreover, if these cost differences are not recognized in rates as they were in the past, it is inevitable that some customers will receive massive increases and others decreases as a result of abandoning these traditional rate relationships. Perhaps most telling is that FirstEnergy recognized this very fact in its 2007 CBP proposal and proposed a reasonable solution.

D. FirstEnergy Should Adjust its Rates to Reflect Class-Specific Cost Differences.

Despite the abundant evidence on the record in this proceeding that generation costs vary by rate class, FirstEnergy proposes to abandon traditional and sound rate making principles by setting near-uniform generation rates that reflect no substantial cost differences among rate classes. FirstEnergy should be required to modify its rate design to reflect the cost differences to serve the various customer classes. Doing so would moderate the rate impacts for large industrial customers and would be consistent with the concept of gradualism by retaining historical rate relationships.

1. FirstEnergy should be required to apply the Class Allocation Factors proposed in the 2007 CBP proposal to the proposed generation rates to develop class-specific rates.

Dr. Goins testifies that the most readily available, reasonable, and straightforward method to adjust the proposed generation rates to reflect class cost differences is to apply the class allocation factors ("CAFs") that FirstEnergy itself proposed for the slice-of-system option in its 2007 CBP proposal. Nucor Ex. 3 at 14. In the 2007 CBP proposal, FirstEnergy developed the CAFs to convert the competitive bid price to an SSO rate for each load class. The CAFs were based on the ratio of each load class' historical average SSO generation and transmission rate to the average of all historical SSO generation and transmission rates. *Id.* at 14; Ex. DWG-3. The CAFs FirstEnergy proposed in the 2007 CBP proposal are as follows:

Rate Class	CAF
RS	1.000
GS	1.252
GP	0.900
GSU	0.800
GT	0.769

Id. at 15; Ex. DWG-3. As Dr. Goins explains, the CAFs should be the first adjustment to FirstEnergy's proposed uniform generation rate, followed by the time-of-use and voltage adjustments. *Id.* at 14-15. If CAFs for additional rate classes are necessary, then FirstEnergy should be required to develop them consistent with the approach used in the 2007 CBP proposal. *Id.* at 15.

Dr. Goins illustrates this method using the proposed 2009 ESP generation rate of \$75 per MWh (\$0.075 per kWh). For residential customers on Rate RS, the CAF-adjusted generation rate would be \$0.075 per kWh (1.000 x \$0.075 per kWh). *Id.* For Rate GT customers, the CAF-adjusted generation rate would be \$0.0577 per kWh (0.769 x \$0.075 per kWh). *Id.* The CAF-adjusted rates would then be further adjusted using the time-of-use weights and voltage differentials proposed by FirstEnergy. *Id.*

The Commission should adopt the CAF adjustment proposed in the 2007 CBP proceeding. Applying the CAFs to the ESP generation rates would retain the historical relationship between the rate classes, which would recognize the cost differences between customer classes to the greatest extent possible in the absence of a cost of service study. The proposal would provide a much greater level of mitigation for large industrial customers than the ESP as proposed by FirstEnergy, and would result in a more reasonable application of the gradualism principle.

Finally, it must be stressed that the CAF concept is not a Nucor creation. Applying these CAFs to recognize cost differences between customer classes is

FirstEnergy's own idea – one that surely has not gone stale in the short time since it was proposed last year. Having proposed the CAFs in the 2007 CBP proposal, FirstEnergy cannot credibly argue that the approach would be unreasonable in the ESP. In fact, despite ample opportunity for FirstEnergy to put evidence on the record against the CAF proposal through rebuttal testimony, FirstEnergy presented no such evidence.

2. The Commission should also adopt OEG's rate mitigation proposal as a complement to the CAF approach.

Nucor was not the only party to identify the problem of FirstEnergy's proposed near-uniform generation rate design and the severe rate impacts on higher load factor and large industrial customers, and to propose alternative cost assignment and rate design options that would address the problem. For example, OEG witness Mr. Baron proposed that no customer class should see a rate increase of more than two times the retail average increase. Direct Testimony of Stephen J. Baron, OEG Exhibit 1 ("OEG Ex. 1") at 20. The effect of this proposal would be to limit the rate increase to Ohio Edison Rate GT customers to 10.47%. *Id.* at 21. OEG's rate mitigation proposal is an improvement over FirstEnergy's proposal, and represents a more reasonable application of gradualism on an inter-class basis. Accordingly, the OEG's rate mitigation proposal can be adopted in conjunction with Nucor's CAF proposal. It should be clearly recognized, however, that Nucor does not recommend Mr. Baron's proposal in lieu of or as an alternative to the CAF, but a complement to it, since the CAF approach addresses the underlying failure of FirstEnergy to properly allocate costs, while the gradualism approach is an after-the-fact limit on the negative impact of the resulting class rate increases.

3. **In the event Nucor's CAF proposal is not adopted, FirstEnergy should be required to retain all existing rates and apply an across-the-board increase to the generation component of those rates.**

An across-the-board rate increase to the generation component of current rates is the most reasonable alternative to Nucor's proposed CAF approach. Under such an approach, all the current rate schedules would be retained (including all firm and interruptible rate schedules; existing contract rates could be retained too with a similar increase approach). The difference between the generation component in each current rate and the generation cost approved by the Commission in the ESP would be recovered through a percentage rider added to the generation component of the rates. For example, if the Commission approves a 5% increase over the current generation rates, a 5% adder would be added to the generation component of each existing rate schedule.

Like the CAF approach, an across-the-board increase would preserve existing rate relationships that reflect the cost differences to serve the various customer classes, and would allow FirstEnergy to recover whatever increased generation costs are eventually approved by the Commission. The huge rate increases high load factor industrial customers will experience under FirstEnergy's proposed ESP would be significantly mitigated. Further, the impacts experienced by each existing FirstEnergy customer would be the same, which would eliminate the problem of "winners and losers" under FirstEnergy's proposed rate design. Each customer – whether it is a residential, commercial, or industrial customer – would remain on its existing rate schedule(s) and experience, for example, a 5% increase in its rates. Finally, an across the board increase would allow the Commission to avoid the contentious rate design issues that have been raised in this proceeding, since the current rate design would be retained.[3]

Several parties in this proceeding have endorsed or acknowledged the approach of applying an across-the-board generation increase to FirstEnergy's existing rates. For example, Staff witness Robert Fortney recognized that an alternative methodology to the proposed ESP rate design could be "an across-the-board increase or matrix approach which maintains the current relationships between classes." Direct Testimony of Robert B. Fortney, Staff Exhibit 5 at 4. To address the disparate rate impacts that would be experienced by non-residential, high load factor customers under the ESP as proposed, Kroger witness Mr. Higgins proposed to modify the generation rate design for any rate schedule that currently has load-factor differentiated generation rates by taking the existing generation-related rate components for these customers and combining them into a single base generation rate. Kroger Ex. 1 at 11. A rate-schedule specific percentage rider would then be applied to recover the requisite change in generation revenue authorized under the ESP. *Id.* at 11-12. As Mr. Higgins explained, this approach would ensure that each customer on the affected rate schedules would experience the same change in generation rates. *Id.* at 12. At the hearing, Mr. Higgins agreed that extending his concept to all current rate schedules would be a reasonable approach. Tr. Vol. IV at 82-83. Even FirstEnergy witness Mr. Blank agreed that FirstEnergy could have proposed an across the board percentage increase on the existing rates. Tr. Vol. VI at 238-39. If

[3] In Case No. 07-551-EL-AIR, FirstEnergy proposed new distribution rates based upon the same consolidated customer classes proposed in the ESP. If the new distribution rates are approved, this would not foreclose the possibility of retaining the current rate structure. If the new distribution rates reflecting the new rate classes are approved, it would be straightforward to simply replace the distribution component in the existing rate schedules with the new distribution rates (reflecting the new rate classes). In this way, the existing rate schedules would be retained, but the distribution charge applicable to each rate schedule would reflect the new distribution rates.

the Commission does not adopt Nucor's CAF proposal, therefore, the Commission should adopt an across-the-board increase to the generation component of FirstEnergy's existing rates, and the existing rates should be retained.

In summary, the evidence on the record in this proceeding demonstrates that FirstEnergy's proposed near-uniform generation rates will result in disproportionate rate increases for large industrial customers. Some industrial customers, in particular interruptible customers like Nucor, will experience rate increases approaching or in excess of 50% in the first year if FirstEnergy's rate design is approved as proposed. Given the perilous state of the economy, and FirstEnergy's statement that its ESP proposal will "promote economic development [and] job retention," (Application at 2), FirstEnergy's proposed rate design is particularly puzzling.

Class cost differences are reflected in FirstEnergy's rates today, and FirstEnergy has previously recognized class cost differences in its rate design whether FirstEnergy proposed to acquire SSO generation supply under a cost-of-service paradigm or under a market paradigm. The need to recognize these class cost differences in the rate design, therefore, is no less valid under an ESP paradigm. In order to recognize class cost differences and to correct the most glaring flaw in FirstEnergy's cost allocation and rate design, FirstEnergy should be required to apply the CAFs proposed in the 2007 CBP proposal to the proposed generation rate in order to calculate class-specific generation rates. In the alternative, FirstEnergy should apply an across-the-board percentage rate increase to the generation component of the existing rates. Under either of these approaches, FirstEnergy's historical rate relationships will be preserved, and the rate impacts to large, high load factor commercial and industrial customers would be mitigated.

III. FIRSTENERGY'S PROPOSED NEW INTERRUPTIBLE RATES ARE INADEQUATE AND MUST BE SIGNIFICANTLY IMPROVED.

Interruptible service is a separately identifiable utility product that allows a supplier to interrupt or curtail customer loads for two different purposes -- when reliability is impaired or for economic reasons. Nucor Ex. 3 at 16. In its ESP, FirstEnergy proposes two interruptible rates – Rider ELR and Rider OLR. The inclusion of interruptible rates in the ESP is welcome, especially compared against FirstEnergy's MRO proposal, which included no interruptible rates. As proposed, however, Rider ELR and Rider OLR would vastly under-value interruptible load, and would impose unnecessarily onerous conditions that would make the riders unattractive to customers. Accordingly, significant improvements should be made to FirstEnergy's proposed interruptible rates:

- A customer's Realizable Curtailable Load should be equal to the customer's monthly peak billing demand minus the customer's firm load – not the customer's average historical demand from peak periods from previous summer months minus firm load, as proposed by FirstEnergy.

- Emergency and economic interruptible programs are separate products and should be separate programs with separate credits, and customers should have the option in participating in one or both programs.

- The credit for emergency interruptions should be no lower than \$7.50/kw/month, which reflects a reasonable (though conservative) estimate of the long-run avoided cost of new capacity.

- The credit for economic interruptions should be no lower than \$2.60/kw/month.

- There should be reasonable limit on the number of hours in which FirstEnergy may call economic interruptions, such as 250 hours, and a reasonable trigger, such as LMPs equal to 125% or more of generation charges for three consecutive hours.

Dr. Goins' testimony includes templates for Rider ELR and Rider OLR that incorporate these proposed changes (except for the 125% trigger, which was recommended by OEG witness Baron). Nucor Ex. 3 at Ex. DWG-5 and DWG-6.

A. Interruptible Load Provides Important Benefits.

FirstEnergy, for good reason, has long included interruptible options in its rates. Tr. Vol. II at 62-63. As Dr. Goins explains in his testimony, interruptible load provides substantial tangible benefits. Nucor Ex. 3 at 17. To begin with, interruptible load allows a utility to reduce generation capacity requirements. *Id.* As FirstEnergy witness Mr. Warvell testified, FirstEnergy does not include interruptible load in its load forecasts, and therefore does not have to plan resources to serve interruptible load. Tr. Vol. II at 41. He agreed that in addition to the capacity avoided, interruptible load also avoids the reserve margin and planning reserve associated with the avoided capacity, as well as distribution losses. *Id.* at 41, 45-46.

Interruptible load is also a vital resource at times of system emergencies when load must quickly be reduced, whether there is a capacity shortage or a problem on the distribution or transmission system. By calling on interruptible load, a utility or transmission provider may mitigate or avoid altogether blackouts or brownouts. Interruptible load has been called in the Midwest ISO in response to emergency situations. Rebuttal Testimony of Kevin T. Warvell, FirstEnergy Ex. 19 ("FirstEnergy Ex. 19") at 4 (noting that Midwest ISO called emergency interruptions on August 1 and 2, 2006). More recently, for example, the Electric Reliability Counsel of Texas has called on interruptible load in response to capacity shortages that threatened system reliability.[4]

Interruptible load provides even more benefits to the system. Interruptible load can potentially be used as operating reserves or other ancillary services. Nucor Ex. 3 at 17. In addition, interruptible load can provide environmental benefits when used to displace fossil generation during periods of peak demand, thereby reducing greenhouse gas emissions. *Id.* Also, economic interruptions provide benefits by allowing a supplier to sell power (either into the market, or to the interruptible customer if the customer elects to buy through) at costs higher than tariff rates when market prices are high.

While interruptible load has provided these benefits for many years, SB 221 includes specific peak demand reduction targets that distribution utilities must meet beginning in 2009. Section 4928.66(A)(1)(b), Revised Code. Although the need for interruptible load was compelling even before the passage of SB 221, this need is even greater now given the peak demand reduction requirements contained in the statute. Given the statutory requirements, retaining the existing interruptible load should be a high priority for FirstEnergy. At the hearing, FirstEnergy witness Warvell agreed that interruptible load would be helpful in meeting the demand response goals of SB 221. Tr. Vol. II at 63. Finally, a good interruptible program is a positive and very important

[4] Press Release, Electric Reliability Council of Texas, ERCOT Demand Response Program Helps Restore Frequency Following Tuesday Grid Event (Feb. 27, 2008) (noting that ERCOT implemented second stage emergency grid procedures following a sudden drop in system frequency caused by a drop in expected energy production, and that, other than interruptible loads, no other customers in the ERCOT region lost power due to the event), *available at* http://www.ercot.com/news/press_releases/2008; Press Release, Electric Reliability Council of Texas, ERCOT Summary of Monday's Electric Grid Events – Voluntary Conservations Efforts Requested for Tuesday (April 17, 2006) (noting that "rolling blackouts" were required due to a generation shortfall related to a heat wave, and that curtailment of interruptible loads appeared to have stabilized the situation until the loss of four generating units necessitated the shedding of firm load), *available at* http://www.ercot.com/news/press_releases/2006.

economic development and industry retention tool for those industries, such as the steel industry, that need such programs to be competitive.

B. Description of Proposed Rider ELR and Rider OLR

FirstEnergy proposes two interruptible riders in its ESP proposal. Rider ELR is available for customers who were on an existing interruptible rate as of July 31, 2008. Customers on Rider ELR are subject to unlimited emergency and economic interruptions. Under Rider ELR, customers receive a $1.95/kw credit, and are also eligible to receive a $6.05/kw credit under Rider EDR. Customers must reduce their load to their firm load within 10 minutes when an emergency interruption is called. FirstEnergy may call an economic interruption for periods where the Midwest ISO LMP is higher than the otherwise applicable tariff rate for three consecutive hours. The customer then has the option to interrupt its load within 30 minutes of notification by FirstEnergy, or buy through at the Midwest ISO market price.

The interruptible load to which the credit will be applied is the customer's realizable curtailable load ("RCL"). Under Rider ELR, the customer's RCL, which is calculated annually, is the difference between an interruptible customer's contract firm load and average hourly demand during the hours of 12 noon to 6:00 p.m. in the preceding months of June-August, with a potential adjustment to reflect economic interruptions.

Unlike Rider ELR, Rider OLR is not limited to customers on FirstEnergy's current interruptible rates as of July 1, 2008. Under Rider OLR, a customer is subject to emergency interruptions, but is not subject to economic interruptions. A Rider OLR customer receives the same $1.95/kw credit contained in Rider ELR, but the Rider OLR customer is not eligible for the additional $6.05 credit contained in Rider EDR. A customer's RCL is measured the same way under proposed Rider OLR as it is under proposed Rider ELR.

C. An Interruptible Customer's RCL Should Reflect the Difference Between the Customer's Peak Billing Demand and its Contract Firm Load.

FirstEnergy's proposed interruptible tariffs contain several features that would under-value interruptible load and shortchange interruptible customers for the service they provide, and therefore likely would lead to reduced customer participation on the rates. One of the most glaring shortcomings is FirstEnergy's proposed RCL measurement. FirstEnergy proposes that the customer's RCL is the difference between the customer's contract firm load and its average hourly demand during select hours in the three peak months of the year. As discussed further below, and as recommended by both Dr. Goins and Mr. Baron, the proper way to measure RCL is the difference between the customer's peak billing demand in a given month and its contract firm load.

1. A customer's actual RCL is the difference between the customer's peak – not average – billing demand and its contract firm load.

When an interruption is called, the interruptible customer must interrupt all of its load in excess of its contract firm load. Application, Volume 2a, Schedule 3a at 81; Tr. Vol. II at 61. In order for the customer's compensation to reflect the actual benefit the customer's interruption provides, therefore, the compensation must recognize that a customer, if it were not interruptible, would have the right to consume energy up to (and beyond) its billing demand. An interruptible customer forgoes this right and should be compensated accordingly. At the most basic level, this is why an interruptible customer's RCL should be the difference between the customer's peak billing demand and its contract firm load. Nucor witness Dr. Goins further explains this rationale in his direct testimony:

> FirstEnergy's definition of RCL ignores its responsibility to serve customer peak demands whenever they occur – not arbitrarily defined average demands that understate the firm capacity and energy requirements that FirstEnergy avoids with interruptible load. FirstEnergy's definition mistakenly assumes that it achieves these avoided cost savings only when interruptible load – maximum demand less firm demand – is on-line and available for interruption. Because of its obligation to serve maximum firm customer demands whenever they occur, FirstEnergy realizes these savings even if interruptible load is not on-line during all hours of its RCL-defined summer peak period. As a result, the monthly credit paid to an interruptible customer should reflect the difference between the customer's monthly peak demand – not historical average demand – and contract firm load.

Nucor Ex. 3 at 22. OEG witness Baron makes the same recommendation on the proper RCL measurement for the same reasons discussed in Dr. Goins' testimony. OEG Ex. 1 at 31.

The RCL measurement recommended by Dr. Goins and Mr. Baron is a more fair, accurate and reasonable measure of the actual load an interruptible customer must interrupt (or, alternatively, the amount of load a customer is prohibited from putting on the system if an interruption is called and the customer is below its peak demand) than the measure proposed by FirstEnergy. This RCL measurement would ensure that interruptible customers would be fully compensated for the interruptibility they provide and, accordingly, would likely ensure a greater level of customer acceptance and participation than FirstEnergy's proposed RCL.

Dr. Goins further explains that basing RCL on average demand, as FirstEnergy proposes, sends an improper price signal to interruptible customers by encouraging them to use more electricity during high-cost summer peak periods. Nucor Ex. 3 at 22. Under this approach, interruptible customers would have an incentive to use electricity more intensively during the summer peak hours to increase their average demands, thereby effectively increasing the level of interruptible credits they receive. *Id.* Encouraging customers to shift their usage to times of peak demand is exactly the opposite of what a well-designed interruptible program should seek to achieve. This perverse incentive is avoided RCL is measured based on peak monthly billing demand.

Another reason why RCL should be measured based on a customer's peak monthly billing demand is to ensure consistency with all the other demand measurements proposed in FirstEnergy's ESP rates. Every demand *charge* proposed in the ESP rates measures demand on the customer's peak – not average – demand.[5] At the hearing, Mr. Warvell testified that the demand measurement used in all the rates with demand charges are the same to ensure consistency, agreeing that consistency is an important goal. Tr. Vol. II at 32-33.

Nevertheless, in the interruptible rates, the one case where a demand *credit* (a payment to the customer instead of FirstEnergy) is proposed, FirstEnergy abandons the need for consistency. At the hearing, Mr. Warvell was asked why FirstEnergy did not use peak demand in the RCL for calculating the level of interruptible load when peak demand is used in all the other demand charges. Tr. Vol. II at 55. Mr. Warvell answered that "[w]e looked at the peak demand and the peak demand compared to the coincident peak for the months does not match up for all of our interruptible customers." *Id.* Mr. Warvell further explained that the RCL measurement FirstEnergy proposes is appropriate

[5] All of the rate schedules with a demand component to the rate (i.e., Rates GS, GP, GSU, and GT) define "billing demand" as the greatest of: (i) Measured Demand, being the highest thirty minute integrated kW or kVA; (ii) a fixed kW or kVA value; or (iii) the Contract Demand. Application, Volume 2a, Schedule 3a, pp. 29, 32, 34, 36. The same billing demand measurement applies to the proposed riders with demand components, such as Rider TAS, Rider DSI, Rider EDR and Rider CCA.

because FirstEnergy must provide Midwest ISO with an "accurate number of what would be required in an emergency situation." *Id.* at 56. However, Mr. Warvell also acknowledged that, in the case of Rider TAS, transmission costs are paid to Midwest ISO based on coincident peak demands, but are billed to the customer based on their non-coincident peak demand. *Id.* at 55. In fact, Mr. Warvell agreed that in the case of all the demand charges proposed by FirstEnergy, *for purposes of consistency*, customers would be billed based on the customer's peak demand whenever it occurred, even though the costs would be caused by coincident peaks. *Id.* at 55-56.

In the end, Mr. Warvell simply could not reconcile having one demand measurement for purposes of measuring interruptible load, and a different demand measurement for all the proposed demand charges. When asked whether the RCL could be based on peak demand for purposes of consistency with the other demand charges, regardless of what FirstEnergy is required to do with respect to interruptible load in Midwest ISO, Mr. Warvell agreed that the RCL could be based on peak demand. Tr. Vol. II at 58.

FirstEnergy should not be allowed to use the customer's peak demand in all of its demand charges (when the customer is required to pay), then use the customer's average demand to calculate the interruptible credit (when the utility is required to pay). For purposes of consistency – a characteristic that FirstEnergy claims is important in its rate design – an interruptible customer's RCL should be measured off of the customer's peak monthly billing demand, consistent with all of the other demand charges proposed in the ESP rates.

2. FirstEnergy provides inadequate justification for its proposed RCL.

By contrast to Nucor's proposed RCL approach, FirstEnergy's RCL would under-compensate interruptible customers by applying the credit to the difference between the customer's average hourly demand during the hours of 12 noon to 6:00 p.m. in the preceding months of June through August. Under this approach, an interruptible customer would receive no compensation for interrupting load that is above the customer's historical average hourly demand in the three summer months of the previous year (or, if the customer is not running at its peak demand when the interruption is called, for committing not to place up to its full load on the system for the duration of the interruption event).

FirstEnergy's justification for its proposed RCL measurement is set forth in Mr. Warvell's rebuttal testimony. According to Mr. Warvell, an emergency interruption is likely to be called for at or around the monthly peak for the system. FirstEnergy Ex. 19 at 3. Mr. Warvell explains that a customer's monthly peak demand is unlikely to coincide with the time of an emergency interruption, and he provides an analysis that purports to demonstrate that the total load of the current interruptible customers on FirstEnergy's system is closer to FirstEnergy's proposed RCL value than to the RCL value proposed by Nucor and OEG. *Id.* at 3, 5-6. Mr. Warvell concludes, therefore, that if FirstEnergy were to assume for purposes of the emergency interruption credit calculation that the load being interrupted was the customer's peak load, the Companies would overcompensate the customer for the value of the interruption. *Id.* at 3-4.

The theory underlying FirstEnergy's RCL, as explained by Mr. Warvell, is fundamentally flawed. By asserting that an emergency interruption is likely to be called at or around the monthly peak for the system, FirstEnergy assumes that emergency interruptions provide a benefit only during these limited hours in the summer months. Based on this assumption, FirstEnergy insists that the RCL should reflect the load of interruptible customers coincident with the system peak. The problem with this approach is that it does not recognize that an interruptible customer may be interrupted *in any hour during any day during any month of the year*, not just during the hours between noon and 6:00 p.m. on weekdays in the months of June through August. Tr. Vol. II at 40. FirstEnergy's approach might make sense if FirstEnergy were willing to limit interruptions to the hours between noon and 6:00 p.m. on weekdays in the months of June through August, but Mr. Warvell it made clear at the hearing that FirstEnergy would not accept such limits on when it could call for interruptions. Tr. Vol. XI at 107.

Mr. Warvell testified on rebuttal that over the last five years, there have been two emergency interruptions called by Midwest ISO, and these occurred on August 1 and 2, 2006. FirstEnergy Ex. 19 at 4. Based on this thin reed of evidence, Mr. Warvell asserts that emergency interruptions will occur at or around the time of the system peak, and that FirstEnergy's proposed RCL measurement is therefore appropriate. On the matter of emergency interruptions, however, Mr. Warvell's testimony lacks credibility. At the hearing, Mr. Warvell testified that he did not know what could cause an emergency interruption and under what circumstances an emergency interruption might be called. Tr. Vol. II at 37-39. When asked by Attorney Examiner Price whether an emergency interruption is defined in the tariff, Mr. Warvell responded that he did not know – this despite the fact that Mr. Warvell is the witness sponsoring Riders ELR and ORL. *Id.* at 38. Nucor's counsel had to point out that the term "Emergency Curtailment Event" is, in fact, defined in the tariff. *Id.* It is difficult to understand how Mr. Warvell could claim not to understand when or why an emergency interruption could be called, but then claim to know that emergency interruptions will occur only at or around the time of the system peak.

Mr. Warvell also apparently does not recognize that there are important differences between the existing interruptible rates and the proposed interruptible rates pertaining to emergency interruptions. When asked whether there are any differences in the standards for when or how an emergency interruption may be called under the existing interruptible tariffs as compared to proposed Riders ELR and OLR, Mr. Warvell responded that they are "very similar." Tr. Vol. XI at 110. The existing interruptible tariffs define an "Emergency Interruption" as follows: "[w]hen the Company determines that the operation of its system requires curtailment of a customer's interruptible service the interruptible customer must interrupt its interruptible load on or before the time specified by the Company." *See, e.g.*, Application, Volume 2a, Schedule 4a at 92. By contrast, proposed Riders ELR and OLR define an "Emergency Curtailment Event" as "one in which the Company, a regional transmission organization, and/or a transmission operator determines, in its respective sole discretion, that an emergency situation exists that may jeopardize the integrity of either the distribution or transmission system in the area." Application, Volume 2a, Schedule 3a at 81, 86. The circumstances under which interruptible load may be called, and obligations for interruptible customers, are actually quite broader under the proposed tariff than under the existing interruptible tariffs – which would mean that interruptible load under the proposed rates would be subject to more conditions, not necessarily peak-related, where it would be subject to interruption and should be even more valuable than under the existing rates. Mr. Warvell was unaware of these key differences.

Further, Mr. Warvell's conclusion in his rebuttal testimony that emergency interruptions occur at or around the time of the system peak was clearly not the result of a careful and thorough analysis of the occurrence of emergency interruptions. Mr. Warvell testified that he did not look at emergency interruptions in Midwest ISO that might have occurred earlier than five years ago. Tr. Vol. XI at 110. He also stated that no probability studies showing the likely timing of emergency interruptions were performed, and that he has no expertise on statistics, probability theory, and standard deviation of variance data. *Id.* at 110, 148. Mr. Warvell did not examine the occurrence of emergency interruptions in other states, or in regional transmission organizations aside from Midwest ISO. *Id.* at 110. Mr. Warvell also testified that he was unaware of major blackouts or brownouts and deployment of interruptible customers that occurred in the spring months in Florida and Texas in recent years. *Id.* at 110-12.

By its very nature, an emergency is unpredictable. In fact, when questioned at the hearing, Mr. Warvell agreed with the general proposition that a problem on the system that could cause an emergency could occur at any time of the year, not just at the time of system peak demand. *Id.* at 113. This proposition undercuts FirstEnergy's claim that emergencies occur at times of peak system demand, and that the level of interruptible load on the system at such times should serve as a benchmark for the RCL that should be established for interruptible customers.

In short, FirstEnergy's claim that emergency interruptions occur at the time of peak demand, and that an interruptible customer's RCL should reflect this, finds no reasonable support in the record. Even if one were to accept FirstEnergy's claim, however, the analysis in Mr. Warvell's rebuttal testimony likely understates the amount of interruptible load that would be on the system at times of peak demand. Mr. Warvell testifies that, in the peak hours of June, July and August of 2007, interruptible customers had an average interruptible load (total load minus firm load) of 351,831 kW. FirstEnergy Ex. 19 at 5-6. According to Mr. Warvell, this average is 85% of the RCL value calculated under FirstEnergy's approach, but is less than 48% of the RCL value calculated using the approach proposed by Dr. Goins and Mr. Baron. *Id.* at 6.

Mr. Warvell's analysis is unreliable for several reasons. First, the analysis was presented in rebuttal testimony with no workpapers and no back-up data. Since the rebuttal testimony was filed just one day before Mr. Warvell took the stand for cross-examination, there was little time for parties to assess Mr. Warvell analysis and, of course, there was no opportunity for discovery. When asked whether he agreed that it was likely that interruptible load on the system when an emergency is called would be higher or lower than the RCL, Mr. Warvell disagreed, testifying that such load would be right at or close to the RCL. Tr. Vol. XI at 106. Mr. Warvell based this conclusion "on history," despite the fact that Mr. Warvell's analysis of interruptible load on the system at times of peak system demand actually looks at only one year – 2007. *Id.*

Further, the effect of economic interruptions on Mr. Warvell's analysis is not clear. If economic interruptions were called during the hours Mr. Warvell examined in his analysis (as would be expected since peak system demand is the time when prices would likely be high), this could have the effect of depressing the RCL because some interruptible customers would have interrupted when they otherwise would have been running. Mr. Warvell testified that that he did not know how many hours of economic interruptions were called during the peak hours in the summer months used in his analysis. Tr. Vol. XI at 117. He stated that the number of economic interruptions was contained in the workpapers, but no such workpapers were included with Mr. Warvell's rebuttal testimony. *Id.*

The discussion above addresses why FirstEnergy's proposed RCL is improper for emergency interruptions. FirstEnergy also argues that the same RCL approach is appropriate for economic interruptions. FirstEnergy Ex. 19 at 7. There is even less of a basis for applying FirstEnergy's proposed RCL in the case of economic interruptions as there is for emergency interruptions. Mr. Warvell testified that in 2007, there were approximately 1,200 hours of economic interruptions, and he acknowledged that economic interruptions are not limited to the months of June, July, and August. Tr. Vol. XI at 117, 122. Mr. Warvell also confirmed that, if a customer is notified of an economic interruption and elects to buy through, the customer's buy-through payment is not limited to the customer's RCL times the buy-through charge. *Id.* at 122. Instead, the customer would be charged the difference between the customer's actual hourly load minus the customer's firm load, times the differential between the LMP and the SSO price. *Id.*

No evidence on the record shows – and FirstEnergy has not claimed – that economic interruptions occur only during the peak summer hours FirstEnergy proposes to use to calculate the RCL. As is the case for emergency interruptions, there is no basis for calculating the RCL for economic interruptions in the way FirstEnergy proposes.

D. Emergency and Economic Interruptible Programs Should be Separate and Customers Should Have the Option of Participating in One or Both.

Emergency and economic interruptible rates have different purposes and underlying values. Because emergency and economic interruptions create different value streams for suppliers, they should be sold as separate, stand-alone products. Nucor Ex. 3 at 20. Establishing emergency and economic interruptible options would provide more choices for customers and should result in more robust participation on the rates. As Dr. Goins explains:

> By offering the emergency and economic buy-through options as separate programs, customers can determine whether they are interested in and want to participate in either or both programs. For example, some customers may have loads suited for short-notice emergency interruptions, while other may have loads more suitable for responding to economic interruptions.

Nucor Ex. 3 at 21.

There has been no evidence offered on the record demonstrating that emergency and economic interruptible load must, or even should, be bundled into a single product. In fact, at the hearing, Mr. Warvell agreed that emergency and economic interruptible load can be viewed as two different products. Tr. Vol. II at 81. FirstEnergy, therefore, should establish stand-alone emergency and economic interruptible rate options and allow customers to participate in one or both options. The appropriate credits for emergency and economic interruptible service are addressed below.

E. The Credit for Emergency Interruptions Should be Significantly Increased.

FirstEnergy proposes a credit for emergency interruptions of $1.95/kw/month. FirstEnergy Ex. 5 at 22. As discussed further below, FirstEnergy's proposed $1.95 credit is too low and is not supported by any reasonable analysis of the costs that FirstEnergy avoids as a result of interruptible load or the benefits that such load provides to the system. A $7.50 credit as recommended by Dr. Goins – while conservative – would be a far more reasonable and appropriate credit.

1. The credit for emergency interruptions should be at least $7.50/kw/month.

Nucor witness Dr. Goins recommends that Riders ELR and OLR include a $7.50/kw/month credit for emergency interruptions. Unlike FirstEnergy's proposed credit, Dr. Goins credit is consistent with the consensus view of how interruptible load should be valued, and is fully supported by the evidence on the record in this case.

An emergency interruptible credit should reflect the long-run marginal cost of peaking capacity (including reserves and adjusted for losses) and incremental transmission capacity costs that can be avoided due to the interruptible load. Nucor Ex. 3 at 23. The basis for Dr. Goins proposed $7.50/kw/month credit is a 2006 report by the U.S. Department of Energy entitled *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* ("DOE Report"). According to the DOE Report:

> Demand response programs designed to reduce capacity needs are valued according to the marginal cost of capacity. By convention, marginal capacity is assumed to be a "peaking unit," a generator specifically added to run in relatively few hours per year to meet peak system demand. Currently, peaking units are typically natural gas turbines with annualized capital costs on the order of $75/kilowatt year.

DOE Report at 74.

In addition to the cost of peaking capacity needed to serve load, interruptible load also avoids the need for capacity needed to meet FirstEnergy's reserve margin. Dr. Goins therefore applied a 15% reserve margin, which is in the same range of the current required Midwest ISO reserve margin. At the hearing, FirstEnergy witness Dr. Jones stated that the current reserve margin in Midwest ISO is 13.5%, and that it he would not be surprised at all if the actual reserve margin is higher. Tr. Vol. III at 92-93. Finally, Dr. Goins applied a 5% factor to reflect avoided losses: ($75 x 1.15) ÷ 0.95 = $90.79/kw/year ($7.57/kw/month). Nucor Ex. 3 at 25, fn.23.

As Dr. Goins explained, his recommend $7.50 emergency interruptible credit is conservative, and there is good reason to believe that an even higher credit could be justified. To begin with, the $75/kilowatt year figure from the DOE Report is based on 2004 data, so it is likely that the capital cost of a peaking generator would be much higher today. Dr. Goins cites to a 2006 report by the Brattle Group entitled *Rising Utility Construction Costs: Sources and Impacts* ("Brattle Group Report") which concluded: "[o]ver the period of 2000 to 2006 . . . the cumulative increase in the installation cost of new combined-cycle units was almost 95%, *with much of this increase occurring in 2006*." Nucor Ex. 3 at 24, fn. 20 (*citing* Brattle Group Report at 8 (emphasis provided)). Also, Dr. Goins did not factor in avoided transmission and incremental fuel cost savings. Nucor Ex. 3 at 25, fn.23.

At the hearing and on rebuttal, no one challenged the use of the $75/kilowatt year capacity figure from the DOE Report or Dr. Goins' calculation of an emergency interruptible credit. This is not surprising, given that Dr. Goins' proposed credit is right in line with average credits for utility interruptible programs in the Midwest ISO region. At the hearing, Dr. Goins testified that an analysis he has seen shows that credits for interruptible programs within the footprint of Midwest ISO range from $2 all the way up to $12, with the average being around $5 or $6. Tr. VIII at 55.[6]

In summary, Dr. Goins' $7.50/kw/month recommendation for an emergency interruptible credit is well supported by the evidence on the record in this case. The record, in fact, supports an even higher credit if avoided transmission and incremental fuel costs are taken into account. The $7.50/kw credit, therefore, should be the minimum credit approved for emergency interruptions.

2. FirstEnergy's proposed $1.95 credit for emergency interruptions is inadequate and unsupported.

In contrast to Dr. Goins' recommended $7.50 credit, FirstEnergy's proposed $1.95 is not even in the ballpark of what would be reasonable for an emergency interruptible credit. FirstEnergy's proposed credit is not supported by any detailed analysis and, for the several reasons discussed below, should not be adopted.

a. FirstEnergy inappropriately relies on short-run market prices for capacity in setting its emergency interruptible credit.

To begin with, the proposed $1.95 credit implies a peaking capacity cost of $23.40/kw/year (12 x $1.95), a cost that is well below the current cost of new peaking capacity. Nucor Ex. 3 at 24. The $23.40 value is less than one third the $75/kW/month value in the DOE Report, which, as discussed above, was based on 2004 data and is also probably below the cost of new peaking capacity today.

It is not surprising that FirstEnergy's proposed credit bears no relation to the long run avoided cost of capacity. FirstEnergy brushes aside the industry standard approach

[6] *See* Ranjit Bharvirkar, Charles Goldman, Grayson Heffner, Richard Sedano, Lawrence Berkeley National Laboratory, *Coordination of Retail Demand Response with Midwest ISO Wholesale Markets* at 20 (May 2008).

for setting emergency/reliability interruptible credits, and instead adopts a short run marginal cost benchmark based on the alleged value of a DNR in Midwest ISO. Mr. Warvell testified that the $1.95 credit is based on a single contract for DNR in Midwest ISO between FES and some other entity, although Mr. Warvell did not know who the other party was, when the agreement was executed, or when the price was negotiated or determined. Tr. Vol. II at 47-48. The price under that contract is $64.00/MW/day, but Mr. Warvell also confirmed that that number does not include a necessary adjustment for avoided reserve charges or avoided losses. *Id.* at 45.

Using a short run marginal cost estimate based on a DNR value as the basis for an emergency interruptible credit is untenable for several reasons. Using a "market" value would likely lead to a fluctuating credit value that would be highly problematic for interruptible customers and that would almost certainly depress customer participation on FirstEnergy's proposed interruptible rates. As Dr. Goins explains:

> [L]ong run avoided costs are the appropriate measure on which to base interruptible credits. Short run market prices fluctuate to reflect the current market conditions for existing generating capacity, while long-run avoided costs reflect the cost of adding new capacity to meet demand growth. Basing interruptible credits on short-run market prices is similar to relying solely on the spot market to meet future energy needs – both approaches increase customer risks via unstable and unpredictable prices. Relying on spot markets is wonderful as long as excess supply exists and prices are low. However, when generation supply becomes scarce, short-run market prices can far exceed the cost of new capacity that cannot be added for several years. Large interruptible customers need and want price (that is, credit) stability and predictability in exchange for making the capital and operating cost commitments necessary to participate in an interruptible program. Basing interruptible credits on short-run market prices of generating capacity is definitely not the way to provide that needed price stability and predictability.

Nucor Ex. 3 at 25-26. At the hearing, Mr. Warvell confirmed that, as proposed by FirstEnergy, the interruptible credit might change from year to year as the capacity markets in Midwest ISO change. Tr. Vol. II at 49-50.

Further, basing the emergency interruptible credit on the value of a DNR does not recognize all the benefits interruptible load provides, and does not account for the differences between interruptible load and a DNR. As noted above, interruptible load provides numerous and diverse benefits to the system, including: the avoidance of generation resources (plus reserve margin and losses) for planning purposes; avoidance or mitigation of emergency situations; potential use as operating reserves or other ancillary services; and the avoidance of transmission costs. *See, supra,* section III.A. A DNR benchmark addresses only the first item on this list (and addresses it poorly because a DNR reflects the value of existing capacity rather than avoided future capacity) while ignoring all the others.

In fact, interruptible load will be able to be used in ways that a DNR cannot be used. For example, interruptible load will have to be able to respond within 10 minutes when an emergency is called. Application, Volume 2a, Schedule 3a at 81, 86. Generating units used to meet the DNR requirement almost certainly will not be able to respond as quickly as interruptible load. Also, generating units are subject to outages, while economic penalties for failing to interrupt, and FirstEnergy's ability to cut off interruptible load if necessary, provide assurance that interruptible load will be available close to 100% of the time. Tr. Vol. II at 42-43. Using DNR as a stand-in for interruptible load, therefore, is like trying to stuff a size twelve foot into a size eight sneaker.

The Commission should reject the use of a short run avoided cost benchmark for the emergency interruptible credit, and should instead require that the credit be based on the long run avoided cost of a new peaking unit, consistent with standard industry and regulatory practice.

b. Even if the value of a DNR was the correct measure for an emergency interruptible credit, FirstEnergy has not demonstrated that its proposed credit reflects the actual expected costs of a DNR for the period of the ESP.

Even if one were to concede that a DNR should be the basis for an emergency interruptible credit, FirstEnergy has not demonstrated that it used an accurate DNR value. As discussed above, Mr. Warvell testified that the DNR value he used to establish the interruptible credit in Riders ELR and ORL was based on a single contract for DNR of uncertain origin. Tr. Vol. II at 47-48. Mr. Warvell also testified that the price under that contract, $64.00/MW/day, does not include necessary avoided reserve charges or avoided losses. *Id.* at 45.

FirstEnergy's testimony on the proper capacity credit simply is not credible because each FirstEnergy witness who addresses capacity cost comes up with a different number. Mr. Warvell uses $1.95, which he claims is taken from a DNR contract between FES and some other party. Dr. Jones starts with a $2.20/kw capacity value, which he testifies was given to him by Mr. Warvell. Tr. Vol. III at 91. He then applies the 13.5% Midwest ISO reserve margin, which results in an effective capacity cost of $2.50 for the years 2009-2011. FirstEnergy Ex. 6 at 13, Ex. 4.

Mr. Graves also received capacity prices from Mr. Warvell for use in his analysis of expected market prices. Tr. Vol. III at 187. Mr. Graves began with capacity costs of $69.17/MW/day for 2009, $82.50MW/day for 2010, and $95.45/MW/day for 2011.

Direct Testimony of Frank C. Graves, FirstEnergy Exhibit 7 ("FirstEnergy Ex. 7") at Ex. 4. To convert these prices to dollars per kW/month as used by Dr. Jones, one would multiply the price by the number of days in the year (365), divide by 1,000 to covert to kilowatts, then divide by twelve to convert to months. This results in a price per kW/month of $2.10 for 2009, $2.51 for 2010, and $2.90 for 2011. Tr. Vol. III at 188. The average of these three years is $2.51/kW/month. *Id.* Adjusting these values to reflect the 13.5% reserve margin results in prices of $2.39/kW/month for 2009, $2.85/kW/month for 2010, and $3.30/kW/month for 2011. *Id.* at 189-90. Averaging these three values together results in a capacity value of $2.84/kW/month for the period 2009-2011.

Three different FirstEnergy witnesses (including Mr. Warvell) came up with three different values for capacity over the term of the ESP ($1.95, $2.50, and $2.84), all based on information provided by Mr. Warvell, and no actual evidence of real market prices was ever provided by FirstEnergy. FirstEnergy's testimony on this matter is simply not consistent or credible. Further, information provided by FirstEnergy last year in the 2007 CBP case suggests that the capacity values proposed by Mr. Warvell and Dr. Jones are low. In the CBP case, FirstEnergy stated that the emergency interruptible credit would be in the range of $2.40 to $3.40 based on market capacity values. Nucor Ex. 3 at Exhibit DWG-4. Mr. Warvell's number is outside of this range, and Dr. Jones' number is within this range but on the low side. Only Mr. Graves' number is comfortably within the range. Thus, even if a DNR value were used, it would make more sense to use a value of between $2.84 and $3.40 for the three years of the ESP than the $1.95 estimate.

F. The Credit for Economic Interruptions Should be No Lower Than $2.60/kw/month.

In his direct testimony, Dr. Goins recommends that a credit for economic interruptions should, at minimum, reflect the expected avoided cost of energy displaced by interruptible load (for example, expected day-ahead Midwest ISO LMPs). Nucor Ex. 3 at 26. This value should be converted to a per kW credit and applied to the customer's RCL. *Id.* at 26-27. Given the time constraints of this proceeding, Dr. Goins chose to rely on the estimates of the value of economic interruptions that FirstEnergy provided in the 2007 CBP proceeding. *Id.* at 27. In that proceeding, FirstEnergy valued the economic interruption credits in a range between $1.60 and $2.60 per kw. *Id.* Nucor Ex. 3, Ex. DWG-4. Dr. Goins recommends at least a $2.60 credit for economic interruptions, and notes that this is a conservative estimate given the rise in fuel prices and LMPs in 2008. *Id.* His testimony about this rise in costs was undisputed.

Unlike Dr. Goins' straightforward recommendation for an economic interruptible credit, FirstEnergy's position on what a proper economic interruptible credit is not quite clear. In fact, FirstEnergy's position on this issue seems to have evolved over the course of the proceeding. At the outset, it appeared that FirstEnergy attributed no value to economic interruptions whatsoever. The $1.95 credit in Rider ELR, under which customers would be subject to both emergency and economic interruptions, is the same credit proposed in Rider OLR, under which customers would be subject only to emergency interruptions. Application, Vol. 2a, Schedule 3a, at 80, 85. In response to a data request asking what value (or credit) per kW FirstEnergy would place on an economic interruption and buy-through program exclusive of any reliability or emergency interruption features, FirstEnergy stated that "[t]here is no value to the

Companies for economic buy through opportunities." Nucor Ex. 3, Ex. DWG-1, Response to Nucor Set 1-13(e). Given this response and the lack of any discussion of the basis for the economic interruption credit in the Application, Dr. Goins concluded that the implied value of economic interruptions to FirstEnergy in Rider ELR is zero. Nucor Ex. 3 at 26.

At the hearing, Mr. Warvell testified that the economic interruptible credit is the \$6.05 credit for interruptible customers contained in Rider EDR. Tr. Vol. II at 65-66; FirstEnergy Ex. 19 at 9. This assertion, however, is inconsistent with the Application and the testimony accompanying the Application. The direct testimony of Mr. Warvell, which supports proposed Riders ELR and OLR, does not say that the credit for economic interruptions is contained in Rider EDR. In fact, while Mr. Warvell explains how FirstEnergy's proposed emergency interruptible credit is derived, his testimony is silent on the economic interruptible credit. FirstEnergy Ex. 5 at 22-23. Likewise, the direct testimony of Mr. Hussing, who sponsors proposed Rider EDR, does not state that the \$6.05 credit for current interruptible customers is intended to be a credit reflecting the value of economic interruptions. Mr. Hussing's testimony is clear that the \$6.05 credit is intended to address rate mitigation and economic development concerns. FirstEnergy Ex. 4 at 8-9 (noting that implementation of Rider EDR, including the interruptible credit provision, "permits mitigation and balancing of customer impacts across the proposed rate schedules as a result of transitioning from current legacy rates and rate design to the proposed ESP tariffs.").

Nucor supports the \$6.05 credit proposed in Rider EDR as an economic development and gradualism credit. Nevertheless, if FirstEnergy's claim that the \$6.05

credit is intended to reflect the value of economic interruptions, FirstEnergy should be required to remove the $6.05 from Rider EDR and put it in Rider ELR and offer it for economic interruptions. If only a portion of the $6.05 credit is intended to reflect the value of economic interruptions, then that portion of the $6.05 should be included in Rider ELR and the remaining portion should remain in Rider EDR. The point is simply that credits intended to reflect the value of interruptible load should be included in the interruptible rider, and credits intended to address rate mitigation and economic development should be included in the economic development rider.

G. The Commission Should Establish A Reasonable Limit on the Number of Allowable Economic Interruptions (250 Hours) and a Reasonable Trigger for Economic Interruptions.

Under FirstEnergy's proposal, there would be no limit on the number of economic interruptions FirstEnergy could call. In Nucor's view, allowing unlimited economic interruptions is unnecessary and is a strong disincentive to customer participation on interruptible rates. Nucor recommends that the number of economic interruptions be capped at 250 hours per year. Nucor also recommends that the Commission adopt OEG's recommendation that the trigger for economic interruptions be three consecutive hours when LMPs are 125% above the applicable kWh net charges in Riders GEN and GPI, rather than 100% as proposed by FirstEnergy.

As explained by Dr. Goins, exposing customers to an unlimited number of economic interruptions would severely limit their ability to control power costs and would increase their risk of unanticipated electricity cost fluctuations each year. Nucor Ex. 3 at 27. In other words, customers would place a high risk premium on the risks associated with unlimited interruptions. Although Dr. Goins testifies that some limit other than 250 hours might be appropriate, he provides an analysis of Midwest ISO day-ahead LMPs at the FirstEnergy hub that demonstrates the reasonableness of a 250 hour limit. *Id.* at 28. Dr. Goins' analysis indicates that day-ahead LMPs exceeded $120 per MWh in 238 hours from January through August, 2008. *Id.* at 27-28. Based on this analysis, Dr. Goins concludes that if economic interruptions were limited to 250 hours annually, FirstEnergy would be able to call economic interruptions to reduce consumption during many of the highest cost hours in Midwest ISO while still encouraging customers to be willing to participate on the economic interruptible rate. *Id.*

In his rebuttal testimony, FirstEnergy witness Mr. Warvell argued that if the number of economic interruptions were limited, there would have to be a corresponding reduction in the interruptible credit. Warvell Rebuttal Testimony at 8-9. Although Mr. Warvell implies in his rebuttal testimony that the $6.05 credit in Rider EDR is the credit that would have to be reduced if the number of economic interruption hours were limited, it is unclear whether this is the case given that it is unclear whether the $6.05 is a credit for economic interruptions, a credit for economic development, or some combination of both. *See, supra,* section III.F.

Although FirstEnergy's claim that a limit on the number of economic interruptions would require a reduction of the credit in this case is meaningless given the uncertainty regarding the economic interruptible credit actually being proposed in this case, Nucor agrees that the economic credit should, in some fashion, reflect the number of hours that a customer would be expected to run the risk of being interrupted. A reasonable way to estimate the minimum appropriate credit given a particular limit on the hours of economic interruptions is to estimate a potential buy-through price and multiply it by the number of hours of potential interruptions, plus a reasonable risk premium for the customer to take the risk of higher buy-through prices. For example, assume a buy-through price of $0.15 per kWh. Multiplying this price by 250 hours results in a credit of $37.50/kW/year, or $3.12/kW/month.

Finally, the Commission should adopt OEG's recommendation that an economic interruption will not be triggered until there are three consecutive hours of LMPs above 125% of energy cost, rather than above 100%. OEG Ex. 1 at 29-30. This approach will limit customer exposure to economic interruptions and will help ensure that economic interruptions are not called unless LMPs are significantly higher than the Rider GEN costs for a sustained period of time. Also, FirstEnergy can have no reasonable objection to such a limitation since FirstEnergy proposed the same limitation in the economic interruptible rate proposed in the 2007 CBP proceeding. *Id.* at 29.

IV. FIRSTENERGY'S PROPOSED TIME-OF-DAY SHOULD BE MODIFIED TO SPLIT THE 16-HOUR SUMMER WEEKDAY PEAK PERIOD INTO TWO SEPARATE PRICING PERIODS.

FirstEnergy's proposed generation rates provide a time-of-day rate option. Under that option, customers would pay a higher rate during a 16-hour peak period, and a lower rate during an 8-hour off-peak period. Application, Vol. 2a, Schedule 3a at 67-68. These daily on-peak and off-peak periods are the same in both the summer and winter periods. FirstEnergy establishes the time-of-use price differentials by calculating a ratio of the average LMP for a particular period in the years 2006-2007 (for example, summer on-peak hours) to the average LMP for those two years. FirstEnergy Ex. 5 at 9-10. FirstEnergy Ex. 5 at 9-10. FirstEnergy then applies this ratio to the generation price to determine the rate for that particular period. *Id.*

Nucor supports the inclusion of the time-of-use option in FirstEnergy's generation rates. Time-differentiated rates that reflect daily cost variations provide better price signals for customers than non-differentiated rates. Nucor Ex. 3 at 29. Without time-of-day pricing, customers would see uniform prices in each hour of the day despite the fact that the cost of electricity varies significantly by time-of-day, which would send inaccurate price signals and lead to inefficient investment and consumption decisions regarding electricity. *Id.* Time-of-day rates not only promote efficient investment and consumption decisions, but they also enhance demand response by encouraging customers to curtail usage at times when prices are high. *Id.*

Although Nucor supports time-of-use rates, the effectiveness of the rates will be limited because the 16-hour peak period is too long. As Dr. Goins explains, the breadth of the proposed 16-hour peak period "significantly restricts customers' flexibility in shifting electricity use to lower-cost hours – particularly in summer months. FirstEnergy provides no empirical justification for selecting a 16-hour daily peak period." *Id.*

The proposed time-of-use option in the ESP generation rates could be significantly improved with a simple fix. The proposed 16-hour summer weekday peak period should be broken into two separate pricing periods – for example, peak and shoulder pricing periods. *Id.* at 30. Dr. Goins recommends that the rate differentials for these two new pricing periods should be set using the same approach that FirstEnergy used in setting the differentials in its proposed time-of-day rates, and Mr. Warvell confirmed that FirstEnergy could add a new time period using this approach. Tr. Vol. II at 104-06.

Nucor recommends that the peak summer period be established as the hours between 11:00 A.M. and 5:00 P.M. on the weekdays. This is the same peak period proposed by FirstEnergy in its proposed residential dynamic peak pricing program, and

Mr. Hussing testified that this six-hour periods was selected for that program because this is the time during the summer when FirstEnergy experiences its peak load. Tr. Vol. V at 73. The remaining 10 hours in the peak period as proposed by FirstEnergy would be considered the shoulder period, and the off-peak period would remain 8 hours as proposed by FirstEnergy.

The result of these changes would be to establish the highest generation prices at the time of FirstEnergy's peak system demand, lower prices during the shoulder period, and the lowest prices during the off-peak periods. This would provide customers with stronger and more accurate price signals than the two-period approach proposed in the ESP rates, and therefore should result in more robust demand response.

V. THE MINIMUM DEFAULT SERVICE CHARGE IS AN IMPEDIMENT TO COMPETITIVE ELECTRIC MARKETS AND SHOULD NOT BE APPROVED.

Proposed Rider MDS is a 1 cent per kWh non-bypassable minimum default service charge that would apply to FirstEnergy customers that take generation service from an alternative supplier. According to FirstEnergy, this charge is also embedded in Rider GEN. FirstEnergy Ex. 5 at 11. FirstEnergy explains that this charge is designed to recover generation-related administrative and hedging costs for SSO service, and to guard against the risk of ESP customers leaving. *Id.* at 10-11.

Extensive evidence on the record in this proceeding demonstrates that: (i) there is no basis for this proposed charge beyond "management's judgment" that 1 cent per kWh is the right charge (Tr. Vol. 1 at 138-39); (ii) FirstEnergy would receive a massive windfall as a result of the charge (*id.* at 122); and (iii) the charge would serve as a significant barrier to competition. See Direct Testimony of David I. Fein, Competitive Suppliers Exhibit 1 at 8-9. As Dr. Goins testified, the types of costs FirstEnergy seeks to recover through Rider MDS should be allowed to be recovered "[o]nly if they have actually occurred, only if they were prudently incurred, [and] only if they could not be negotiated away through the FES contract." Tr. Vol. VIII at 52-53. The proposed minimum default service charge is inconsistent with these principles and therefore should be rejected.

If, however, the Commission approves the minimum default service charge contained in Rider MDS and embedded in Rider GEN, Nucor urges the Commission to adopt OEG's proposal that the charge should be waived for a customer that: (a) agrees to forgo its right to shop during the three year term of the ESP, or (b) agrees to not take service under the ESP and, in the event of a return to POLR service, agrees to waive its right to take service under the ESP and accept market based rates. OEG Ex. 1 at 26-27. This is a reasonable compromise that would significantly mitigate FirstEnergy's risk while keeping customers who have no intention of shopping during the term of the ESP from being burdened with the minimum default service charge.

VI. FIRSTENERGY'S PROPOSED GENERATION RATES ARE EXCESSIVE AND SHOULD BE SIGNIFICANTLY REDUCED.

The only justification FirstEnergy provides for its proposed generation rates (7.5 cents/kWh hour in 2009, 8.0 cents/kWh in 2010, and 8.5 cents/kWh in 2011) is that the rate is lower than generation would be available in the market. FirstEnergy Ex. 5 at 4. FirstEnergy relies on the market estimates of its witnesses Dr. Jones and Mr. Graves for support. *Id.* Since FirstEnergy filed its Application, however, wholesale prices have steadily dropped. Evidence on the record suggests that wholesale prices are now more than 20% below where they were in July. Update to Direct Testimony of Lane Kollen, OEG Ex. 2A.

Nucor urges the Commission to give careful consideration to the evidence on the record indicating that FirstEnergy's market price estimates are well overstated. If the market price estimates in FirstEnergy's Application are overstated, then the proposed ESP generation rates are overstated as well.

VII. THE CAPACITY COST ADJUSTMENT RIDER SHOULD NOT APPLY TO INTERRUPTIBLE LOAD.

FirstEnergy proposes a capacity cost adjustment rider ("Rider CCA") to recover projected costs for capacity purchased to meet planning reserve requirements. Application, Vol. 2a, Schedule 3b at 18-19. As confirmed by Mr. Warvell at the hearing, FirstEnergy does not have to acquire planning reserve for interruptible load. Tr. Vol. II at 41. Accordingly, Rider CCA should not apply to interruptible load. Similarly, FirstEnergy would not include interruptible demands in the figures provided to Midwest ISO that result in the costs under Rider CCA. *Id.* at 33. Interruptible customers should only have to pay Rider CCA on the portion of the load that is firm. OEG Ex. 1 at 32.

VIII. IF AN ESP IS NOT APPROVED AND IN PLACE BY JANUARY 1, 2009, FIRSTENERGY SHOULD BE DIRECTED TO RETAIN ITS CURRENT RATES UNTIL AN ESP OR MRO IS APPROVED.

FirstEnergy's ESP proposal is a complex and detailed plan, and parties in this proceeding have raised a myriad of concerns about almost every aspect of the proposal. We believe that the Commission should not approve the ESP as filed, but instead either "modify and approve" the Application, or reject the proposal altogether. Section 4928.143(C)(1), Revised Code. Pursuant to Section 4928.143(C)(2)(a) of the Revised Code, if the Commission modifies and approves the Application, FirstEnergy may withdraw the Application, thereby terminating it, and may file a new application.

Section 4928.143(C)(2)(b) of the Revised Code provides that if the Commission rejects or approves and modifies an ESP application, the Commission shall issue an order as is necessary to "continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively."

In the event that the Commission rejects or modifies and approves the ESP, we recommend that the Commission implement the provisions of Section 4928.143(C)(2)(b). There are two possible factors unique to FirstEnergy that might impact the rates currently in effect, but neither of these factors would require the Commission to deviate from the statutory scheme. The first factor is the termination of FirstEnergy's contract with FES at the end of this year. If the FES contract terminates and there is no ESP (or MRO) to replace it, FirstEnergy will have to make alternate arrangements to obtain power supply to serve its SSO load. Acquiring power from a new source (or under a new contract with FES), however, would not require a change in the provisions, terms, and conditions of FirstEnergy's current standard service offer. FirstEnergy should be required to continue its current rates, but should be allowed to recover (or credit) the difference between the generation costs reflected in the existing rates and the reasonable and prudent cost to FirstEnergy of procuring generation until an ESP or MRO is approved. Since FirstEnergy does not own generation, this course of action would be most consistent with the requirement in Section 4928.143(C)(2)(b) to continue existing rates "along with any expected increases or decreases in fuel costs from those contained in that offer."

The second factor that could affect FirstEnergy's current rates is FirstEnergy's pending distribution rate case, Case No. 07-751-EL-AIR. In that case, FirstEnergy proposed new customer classes for distribution rates (the new customer classes are the same as those proposed in the ESP). If the new distribution rates reflecting the new rate classes are approved, the Commission should simply replace the distribution component in the existing rate schedules with the new distribution rates (which will reflect the new rate classes). In this way, the existing rate schedules would be retained, but the distribution charge applicable to each rate schedule would reflect the new distribution rates.

In summary, if the Commission rejects or modifies and approves FirstEnergy's ESP proposal, we recommend that the Commission issue an order continuing the provisions, terms, and conditions of FirstEnergy's current standard service offer under Section 4928.143(C)(2)(b) of the Revised Code. Neither FirstEnergy's pending distribution rate case nor the expiration of FirstEnergy's existing contract with FES would require the Commission to follow a course of action different from that prescribed in Section 4928.143(C)(2)(b) of the Revised Code.

IX. CONCLUSION

Nucor respectfully requests that the Commission reject, or modify and approve, FirstEnergy's ESP, and that the Commission adopt the recommendations set forth above.

Respectfully submitted,

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I hereby certify that a copy of the foregoing pleading was served upon the following parties of record or as a courtesy, via electronic transmission, on November 21, 2008.

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