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Public Utilities Commission of Ohio
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180 E. Broad Street, 10th Floor
Columbus, Ohio 43215

In re: Case No. 08-935-EL-SSO

Dear Sir/Madam:

Please find enclosed an original and twenty (20) copies of the BRIEF OF OHIO ENERGY GROUP ON LONG TERM ESP fax-filed today in the above-referenced matter.

Copies have been served on all parties on the attached certificate of service. Please place this document of file.

Respectfully yours,

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BEFORE THE

PUBLIC UTILITY 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 R.C. §4928.143 In The Form Of An Electric Security Plan	:	**Case Nos. 08-935-EL-SS0**

BRIEF OF OHIO ENERGY GROUP

ON LONG TERM ESP

The members of the Ohio Energy Group ("OEG") who purchase electricity from the Ohio utilities owned by FirstEnergy are: Air Products and Chemicals, Inc., AK Steel Corporation, Alcoa Inc., ArcelorMittal USA, BP-Husky Refining, LLC, Brush Wellman, Inc., Charter Steel, Chrysler LLC, Ford Motor Company, Johns Manville, Linde, Inc., North Star BlueScope Steel, LLC, PPG Industries, Inc., Republic Engineered Products, Inc., Severstal Warren, Inc. (formerly WCI Steel, Inc.), Sunoco, Inc. (R&M) and Worthington Industries.

These large industrial companies employ approximately 53,000 people in Ohio. These are high wage, high benefit, family supporting jobs. The OEG member companies served by FirstEnergy have a load of over 1,000 MW and consume approximately 6.4 billion kWh per year. While the cost of electricity is not the only factor that will determine if these companies can continue to operate in Ohio, it is a major factor. OEG submits this brief on the long term ESP.

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I. INTRODUCTION AND STANDARD OF REVIEW

On July 31, 2008 Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company ("TE"), (collectively the "Companies") filed their Application requesting approval of their proposed Electric Security Plan ("ESP"). The central provision of the ESP is an offer from FirstEnergy Solutions ("FES") to provide generation at 7.5 cents per kilowatt-hour (kWh) in 2009, 8.0 cents per kWh in 2010, and 8.5 cents per kWh in 2011 (plus adders for fuel, fuel transportation, environmental costs, and other costs) for customers who choose to receive generation service from their distribution company. This proposed ESP purchase from FES is to replace the existing FERC-approved all-requirements wholesale supply contract which expires at the end of 2008. The maximum price FES can charge the Companies under the existing contract is $53.62/mWh.[1]

Senate Bill 221 provides that an electric distribution utility may file an Electric Security Plan ("ESP")(RC §4928.143(A)), that provides for automatic recovery of certain generation costs including purchased power acquired from an affiliate, "*provided that such costs are prudently incurred.*" (RC §4928.143(B)(2)(a)) The utility has the burden of proving that the ESP is "*more favorable in the aggregate as compared to the expected results*" of the utility's Market-Rate Offer ("MRO") (RC §4928.143(C)(1)). ESP filings are also subject to the §4928.02(A) and (N) policy requirements that the Commission "[e]*nsure the availability to consumers*" of "*reasonably priced retail electric service,*" and "[f]*acilitate the state's effectiveness in the global economy.*"

The Commission should interpret RC §4928.143 to give effect to all of its parts and consider, in context, all of the words used giving effect to the overall statutory scheme. *D.A.B.E., Inc. v. Toledo-Lucas County Board of Health*, 96 Ohio St.3d 250 (2002). *See also, State v. Arnold*, 61 Ohio St.3d 175,

[1] FirstEnergy Solutions Corp., Docket No. ER06-117-000, 117 FERC ¶61,278 (2006).

178 (1991) (a statute shall be construed, if practicable, as to give effect to every part of it). This means that to gain Commission approval the Companies have the burden of proving that its ESP plan is 1) more favorable than the MRO (RC §4928.143(C)(1)); 2) contains only costs that are "*prudently incurred.*" (RC §4928.143(B)(2)(a)); and 3) conforms to the policy requirements that it provides "*reasonably priced retail electric service,*" and "[f]*acilitates the state's effectiveness in the global economy.*" (RC §4928.02(A) and (N)).

The Companies contend that their Application is "*considerably more favorable*" to customers than the MRO alternative.[2] The Companies presented no evidence that their proposed purchase from FES is "*prudent*". Nor did the Companies attempt to demonstrate that their ESP will result in "*reasonably priced retail electric service.*"

[2] Application p. 6.

II. ARGUMENT

1. THE COMPANIES' PROPOSED ESP SHOULD BE MODIFIED BECAUSE IT IS NOT "MORE FAVORABLE IN THE AGGREGATE" THAN THE MRO.

RC §4928.143(C)(1) requires that the Companies prove that their ESP is "*more favorable in the aggregate as compared to the expected results that would otherwise apply under*" the MRO option. If the utility does not meet this burden, then the Commission cannot approve the ESP without modification. In making this determination, the statute specifically cites "*pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals.*"

The Companies provided a quantitative comparison of their projections of the retail revenues they will recover under both the MRO option and the ESP option on a net present value basis. The Companies' market price projections are from July 15, 2008. There projections attempt to establish that the proposed ESP will provide lower rates than the MRO. It shows a $1,303.4 million net present value benefit to ratepayers from the Companies' proposed ESP compared to its quantification of the MRO option over the three-year life of the proposed plan plus the additional seven-year deferral recovery period. However, the Companies' analysis suffers from serious errors that overstate the benefit of its ESP. When these errors are corrected it becomes clear that the Companies' proposed ESP fails the statutory test that the ESP must be "*more favorable in the aggregate*" than the MRO.[3]

a. The Companies' Analysis Contains Errors In Computing Forward Market Prices.

Company witness David Blank's Direct Testimony shows a $1,303.4 million net present value benefit to ratepayers from the Companies' proposed ESP compared to its quantification of the MRO option over the three-year life of the proposed plan plus the additional seven-year deferral recovery

[3] Direct Testimony of Lane Kollen pp. 5-6.

period.[4] Mr. Blank computed the MRO revenues based on the average of hypothetical market prices that the Companies' project will result if they are permitted to outsource all responsibility for supplying generation service to non-shoppers through a reverse auction. The hypothetical market prices were constructed by Mr. Frank C. Graves of the Brattle Group and Dr. Scott Jones of FTI Consulting.[5]

However, Mr. Blank's calculation contains several computational errors that significantly effect his results. Mr. Blank incorrectly computed the market prices developed by Mr. Graves and Dr. Jones for purposes of the MRO revenue quantification by failing to remove the entirety of the transmission component included in those prices. Mr. Blank failed to gross up the transmission component for line losses. [6]

OEG witness Lane Kollen revised Mr. Blank's calculations to correct this error (see Mr. Kollen's Exhibit__(LK-3)). The effect of correcting this computational error is to reduce the ESP benefit computed by Mr. Blank from $1,303.4 million to $1,242.2 million on a net present value basis.[7] Mr. Blank subsequently filed Co. Ex. 1A and 1B entitled "Alternative Attachment 1" and David M. Blank Direct Testimony Adjustment Corresponding to Alternative Attachment 1, respectively. In these exhibits Mr. Blank essentially accepts Mr. Kollen's correction of the computational error relating to Mr. Blank's failure to gross up the transmission component for line losses as well as two other errors pointed out by Michael Schnitzer, a witness for Constellation New Energy. The errors or corrections discovered by Mr. Schnitzer related to the failure of Company witnesses Jones and Graves to treat congestion and line losses associated with non-network transmission services equally as between the pricing of the ESP versus the MRO. Company Exhibit 1A shows the consequence of correcting these errors is reduce the

[4] Direct Testimony of David Blank, Attachment 1.
[5] Direct Testimony of Lane Kollen p. 6.
[6] Direct Testimony of Lane Kollen p. 7.
[7] Direct Testimony of Lane Kollen p. 8.

Company's calculation of the benefits of the ESP over the MRO down to $1,008.3 million. (*See* Co. Ex. 1A, p. 1 of 4, last line under "Total Ohio"; and TR Vol. V, p. 197).

b. <u>The Hypothetical Market Prices Used By The Companies Do Not Reflect The Recent Downturn In Market Prices.</u>

The hypothetical market prices used by the Companies do not reflect the recent substantial decline in market prices. Both Mr. Graves and Dr. Jones used the July 15, 2008 forward prices for the energy component of their hypothetical market prices. The MISO and PJM West forward prices have declined significantly since July 15, 2008. OEG has obtained the October 10, 2008 MISO and PJM forward prices from NYMEX and used these prices to revise Mr. Graves' calculations. It is imperative that the Commission use the most recent available market data when considering the proposed ESP. As Attorney Examiner Price pointed out at hearing, and Dr. Jones agreed, the *"data"* that is *"closer in time"... "to the Commission*['s] *decision"* on the ESP *"is the better data."*[8] The market conditions that influenced the prices in effect on July 15, 2008 are a world away from the market conditions that existed on October 10, 2008 and today. The July 15th prices are largely irrelevant.

Using more recent forward prices to construct the wholesale market prices for the revenues under the MRO option has a dramatic effect on the MRO versus ESP quantification. The ESP benefit computed by Mr. Blank of $1,008.3 (as corrected in Ex. 1A) is completely wiped out. The new numbers show that the MRO represents a $686 million benefit over the ESP on a net present value basis.[9] The ESP could be rejected on this basis alone.

[8] TR Vol. III p. 109, lines 11-16.
[9] Direct Testimony of Lane Kollen, Exhibit___(LK-9A).

OEG presented the following Table which tracks the fall in wholesale generation prices since this case was filed. Using the same methodology as the Companies' witnesses, this Table shows that since this ESP was submitted wholesale generation prices have fallen 24%.[10]

Table 4
Average of Cinergy Hub and PJM West Forward Prices

Month	July 15, 2008	Sept. 19, 2008	Oct 10, 2008
Jan-09	366,491,657	301,744,112	265,706,909
Feb-09	322,780,327	265,802,942	233,954,477
Mar-09	279,537,902	239,778,174	213,283,427
Apr-09	282,923,809	244,497,973	214,979,554
Jan-Apr Avg.	1,251,733,695	1,051,823,202	927,924,366
Capacity Cost Rate ($/mW/day)	69.17	69.17	69.17
Peak Load + Reserves	13,327	13,327	13,327
Capacity Cost (@ 120 Days)	$110,619,431	$110,619,431	$110,619,431
Total Cost	$1,362,353,125	$1,162,442,633	$1,038,543,797
MWH Sales	18,794,716	18,794,716	18,794,716
$/mWh	$72.49	$61.85	$55.26

This Table is only updated through October 10, 2008. Since then the market price for generation has continued to remain well below the July 2008 levels. Appendix A to this brief shows the average Cinergy Hub day ahead prices over the last twelve months. The Cinergy Hub and FirstEnergy are both in MISO. Appendix A shows that MISO LMP prices have averaged about $40/mWh for at least the last three months. Not surprisingly, MISO prices directly correlate to MISO load. Reduced demand for power means reduced market prices. (Appendix B). MISO's 2008-2009 Winter Reliability Assessment

[10] Update of Table 2, p. 14 of Baron Direct Testimony to reflect Cinergy Hub and PJM West forward prices of October 10, 2008.

concludes that a slowing economy combined with increased demand response programs will result in a peak demand that is 3.72% lower than last year. The same report projects a MISO reserve margin for the 2008-2009 winter of 33,366 MW, or 42% of the coincident net internal demand. (Appendix C). Natural gas pricing (which sets the LMP clearing price on-peak) tells the same story. Natural gas prices peaked at about $15/mmBtu in July 2008, about the same time this ESP was filed. Today, NYMEX natural gas futures for at least the next twelve months are in $6.5 – $7.0 range. (Appendix D).

These numbers show not just that electricity prices on July 15, 2008 were higher than on September 19, 2008 and that prices were higher on September 19 than on October 10,2008 but that there is a clear line reflecting an obvious <u>trend</u> to lower electric power prices that is reinforced and explained by the economic upheaval of current times.

In a very real sense, the Commission is not merely regulating the First Energy Companies, but negotiating with FirstEnergy on behalf of millions of consumers. The dramatic fall in energy prices since the ESP was filed cannot be ignored.

c. <u>The Companies' Comparison Of The MRO And ESP Options Incorrectly Includes A Retail Margin In The MRO Wholesale Supplier Market Prices.</u>

The Companies have created a fundamental mismatch between the MRO and ESP options by including a retail margin in the MRO wholesale supplier market prices. The Companies' include all wholesale generation prices plus all retail risk premiums expected to result from a reverse auction in its MRO quantification. In contrast, its ESP analysis includes only the base wholesale generation prices offered by FES ($75/MWH, $80/MWH, and $85/MWH for 2009, 2010, and 2011, respectively), with no attempt to quantify the full wholesale generation price or the full retail risk premiums. When only part of the ESP costs are compared with all the reverse auction MRO costs, it is no wonder that the Companies' comparison shows that the ESP is more favorable in the aggregate than its MRO.

The additional ESP costs that are not included in the Companies' analysis are: 1) increases in fuel transportation surcharges above a baseline; 2) costs associated with alternative energy/renewable requirements beyond those specified in SB 221; 3) new taxes or environmental requirements which exceed $50 million during the ESP period; 4) increased fuel expenses in 2011; 5) increased capacity purchases required to meet FERC, NERC or MISO reserve margin standards; and 6) the proposed $10/MWH non-bypassable minimum default service charge for POLR risk. This $10/MWH POLR charge is a retail risk premium cost of the ESP option, which alone could cost consumers up to $1.7 billion over three years.[11]

Removing the retail risk premiums from the revenues under the MRO option deepens the divide between the MRO versus ESP analysis so that the MRO revenues are less than the ESP revenues by $2,417.8 million on a net present value basis, meaning that the MRO option represents significantly lower cost to ratepayers than the Companies' proposed ESP. Consequently, on a quantitative basis, the ESP is not "*more favorable in the aggregate*" than the MRO and it fails the statutory test for Commission approval without modification.[12]

2. THE COMPANIES' ESP PROPOSAL CONTAINS COSTS THAT ARE NOT "*PRUDENTLY INCURRED*" AND THEREFORE SHOULD NOT BE ALLOWED.

RC §4928.143 provides for automatic recovery of "*the cost of purchased power supplied under the* [ESP], *including the cost of energy and capacity, and including purchased power acquired from an affiliate provided that such costs are prudently incurred.*" (RC §4928.143(B)(2)(a)) The prudence

[11] Direct Testimony of Lane Kollen p. 12.
[12] Direct Testimony of Lane Kollen, Exhibit__(LK-10A).

standard necessarily encompasses the concept of purchasing power on a least cost basis. The Companies have ignored this requirement. Nowhere in the Companies' Application do they attempt to establish that the requested costs are prudent. Additionally, on cross-examination by OEG, Company witness David Blank stated that those proposing the FE ESP *"haven't thought about the plan relative to least costs."*[13] It appears from the Companies' Application and testimony that they believe they are merely required to show that the proposed ESP is more favorable than the MRO option. Although, as explained above, the Companies fail this requirement, they also fail the prudency test that they have not addressed. OEG has identified several cost-items contained in the Companies' proposed ESP that are not *"prudently incurred."*

a. <u>The FES Price Does Not Reflect Prudently Incurred Power Prices And Must Be Lowered To Reflect Current Market Prices.</u>

The Companies propose to purchase generation from its affiliate, FirstEnergy Solutions, Inc., through a no-bid sole-source contract.[14] As just discussed, the generation costs suggested by FES start with numbers layered one after another on a foundation that is far higher than the real current bare bones wholesale cost of power. Unless the FES offer price is lowered to reflect current market conditions, the Commission should modify the ESP so that the wholesale price of power to the Companies consists of a least-cost (prudent) portfolio of generation products.

Because none of the distribution utilities own generation, they must purchase wholesale power for non-shopping load under the ESP. Under an ESP, the distribution utilities should develop a least-cost generation portfolio to meet the projected needs of their non-shopping load. This generation portfolio would include a reasonable mix of fixed block wholesale contracts and spot purchase and sales

[13] TR Vol. V, pp. 251.
[14] Direct Testimony of Lane Kollen p. 14.

contracts (to deal with load following, sales forecast variation, shopping migration, etc). The utilities could develop this least cost portfolio or they could hire an independent third party to do it for them.[15]

The distribution utilities would absorb the POLR costs associated with retail customer choice and would be compensated for those POLR costs at rates regulated by the Commission. Under this procurement approach, the Commission would have oversight on both the level and recovery of retail risk premiums (POLR) being charged to customers.

If retail shopping terms and conditions are under the PUCO jurisdiction, the Commission has the statutory authority to place limitations on customer shopping through non-bypassable charges. RC §4928.13(B)(2)(d). If it does this, then the Commission could reduce the ESP POLR costs. Reducing ESP POLR costs should benefit all non-shopping consumers. Also the Commission has the power to provide that customers who contractually agree not to shop or who agree at the outset to shop and only return to the ESP at market rates should not be subject to the POLR charge.

This benefit is potentially large. Company witness Dr. Jones explained how third parties who bid on supplying non-shopping load must factor in many different types of retail risk. According to Dr. Jones, when utilities out-source the responsibility and risk of POLR supply to third parties, the result is a retail mark-up over the wholesale generation price of between 17% - 40%. Keep in mind that this retail mark-up is over and above the FERC-regulated wholesale market generation prices established through the MISO or PJM locational marginal price (LMP) process.[16]

The Companies have not demonstrated that the purchased power expenses they will incur pursuant to their ESP are prudent as required by §4928.143. The prudence standard requires that the utilities obtain their power to supply the POLR requirements at the least reasonable cost, not simply at

[15] Direct Testimony of Lane Kollen p. 14.
[16] Direct Testimony of Stephen Baron p. 9.

some discount to a fundamentally flawed and excessive hypothetical market price used to quantify the MRO option.

The Companies fail the prudence standard. The proposed base generation rates are in excess of wholesale FERC-regulated market prices and are not prudent on that basis alone. When the base generation rates are combined with the effects of the various generation and POLR riders, the problem is exacerbated.[17]

b. The Acquisition Process Of Purchasing Power From An Affiliate Without Bids And Without The Review Or Even The Existence Of A Wholesale Power Contact Between FES And The Affiliate Utility Is Imprudent.

The Companies' base generation rates as well as all the riders are the result of self-dealing with their FES affiliate and are not the result of a properly conducted procurement process. The expected costs of the riders are not in the record and thus, cannot be realistically assessed. The utilities have the obligation to obtain their power at the least cost; they do not have the right to recover open-ended purchased power expenses at rates that were not subject to arm's length negotiations simply because the wholesale supplier is an affiliate.[18]

Second, there are no contracts to review for the Commission to assess whether the pricing and other terms merit the proposed ESP generation rates and riders. The Companies have not provided or made available a copy of the purchased power contracts between each Company and FES and were not able to provide any substantive information concerning how the Companies derived the generation rates that they propose to charge customers. At hearing, Companies witness Mr. Warvell claimed that he had no knowledge of "*any of the particular aspects of negotiation*[s]" between the Companies and FES,[19] or

[17] Direct Testimony of Lane Kollen p. 20.
[18] Direct Testimony of Lane Kollen p. 20.
[19] TR Vol. I, p. 21 lines 7-11.

"*any of the terms or conditions that are being considered by FES and* [the Companies],[20] Mr. Warvell stated that the generation rates proposed by the Companies were the product of "*a group of people involved in studying... where market prices were at* [and] *certain auctions that it cleared, different wholesale prices, risks involved with those wholesale prices, and the determination of a basic understanding of the Senate Bill 221.*"[21] However, Mr. Warvell could not provide any further insight as to how the proposed rates were derived, stating that he was not aware of any "*minutes, documents*", or "*notes of the meetings.*"[22] The Companies have not provided the Commission with any of the information needed to evaluate the reasonableness of the Companies' transactions with FES and the generation prices that result. It is impossible for the Commission to judge their prudence.[23]

The Companies have simply presented the Commission with black-box generation prices that they "negotiated" with an affiliate. They have not produced a single contract to evaluate or a single substantive detail concerning how these prices were conceived. Yet they are asking the Commission to take it on faith that the prices and terms of this $13.85 billion deal with FES are reasonable and prudent.[24] The Commission must not approve these generation prices without better information.

Absent a submission by the Companies of a dramatically reduced generation price from FES with full disclosure of contract terms, the Commission should direct the Companies to structure a least-cost purchased power supply portfolio that minimizes their purchased power expense. Such a supply portfolio would be similar in concept to the purchased gas portfolios of natural gas distribution utilities. These purchases should be made only at transparent and verifiable FERC-regulated wholesale market

[20] TR Vol. I, p. 21 lines 12-19.
[21] TR Vol. I, p. 26 lines 10-16.
[22] TR Vol. I pp 26-27.
[23] Direct Testimony of Lane Kollen p. 20.
[24] TE Vol I, p. 172 (Warvell).

rates so that the Commission can verify that they are prudent and reasonable. The Companies should retain and be compensated for their actual expenses incurred due to retail market risks.[25]

3. OEG'S RATE MITIGATION PLAN WOULD ENSURE THE AVAILABILITY OF "*REASONABLY PRICED ELECTRIC SERVICE*" AND "*FACILITATE THE STATE'S EFFECTIVENESS IN THE GLOBAL ECONOMY.*"

The Companies have proposed a number of so-called "rate mitigation" riders that are designed to facilitate a reasonable transition from the current RSP rates to the proposed rates that would otherwise prevail under their respective ESP's. For example, Mr. Hussing testifies at page 5, line 9 of his testimony that:

> "*The 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 customer impacts. Incorporating the concept of gradualism is a useful tool in managing overall customer impacts resulting from rate design objectives.*"

Although the Companies' stated objectives are certainly reasonable, the Companies' proposed rate increases under the ESP shows that the utilities have not come close to incorporating gradualism into their rate proposals and have failed to adequately mitigate the increases to large industrial customers, the class which will be most dramatically affected by the ESP increases.

The Table below summarizes the percentage rate increases by rate class for each Company in 2009, compared to 2008 rate levels:[26] This Table includes the deferrals requested by the Companies.

[25] Direct Testimony of Lane Kollen p. 21.
[26] Direct Testimony of Stephen Baron p. 18.

Companies' Proposed Rate Increases
Including Effect Of Proposed Deferrals

RATE CODE	2009 / 2008 Percentage Increases OE	CE	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%
TOTAL COMPANY	5.23%	4.62%	6.96%

Rate GT is the transmission voltage rate used to serve large industrial customers. The proposed ESP increases for large industry are many multiples of the average retail increases for the Companies.[27] In the case of Toledo Edison, the Company is proposing to increase the GT industrial rate by 33.8%, compared to an average retail increase of 6.96%. At the same time, Toledo Edison is proposing significant rate reductions for the commercial customer classes. The GT industrial rate increase is nearly 5 times as large as the average increase. This cannot possibly be consistent with the concept of gradualism supported by Mr. Hussing.[28] However, these rates reflect the full extent of the Companies' proposed mitigation assistance.

The Companies' proposed rates are not consistent with Ohio state policy, as required in Ohio RC §4928.02. RC §4928.02(A) and (N) provide clear guidance to the Commission in evaluating the Companies' ESP. These policy objectives are to:

> "*(A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;* [and]
>
> *(N) Facilitate the state's effectiveness in the global economy."*

[27] Non-standard tariffs such as Street Lighting, etc., are excluded from this Table.
[28] Direct Testimony of Stephen Baron p. 17.

Increases for the Companies' largest industrial manufacturing firms in the range of 25% to 34%, compared to retail average increases in the 5% range and commercial class rate reductions, do not comport with Ohio state policy requiring reasonably priced electric service and clearly do not "*facilitate the state's effectiveness in the global economy.*" A more substantial and reasonable mitigation plan is required.

While reasonably priced electric power will not save Ohio's manufacturing sector by itself, it will help enormously. From January 2000 to the first quarter of 2008, Ohio's goods-producing industries (manufacturing, construction, natural resources, and mining) lost 23.3% of their employment. In the last eight months this rate of decline has accelerated. From January 2008 to August 2008, Ohio's unemployment rate increased by 34.5% (from 5.5% to 7.4%). This is 115,888 additional unemployed workers. Heavy manufacturing is concentrated in the Companies' service territories. According to the Ohio Department of Development, in 2007 Ohio had 201 large manufacturing plants. Of this total, 161 are located in counties served by the Companies.[29]

Keep in mind that the above numbers predate the start of the recent economic downturn which is already being felt by Ohio industrial customers. The shipping and package delivery company, DHL recently announced that it would cut almost 7,000 jobs in Wilmington, Ohio, more than half of the small town's population.[30] In FirstEnergy's service territory alone there are hundreds of businesses that are threatened by the potential bankruptcy of the Big Three automakers.[31] This is not the time to raise electric rates on the industrial customers that provide hundreds of thousands of high-paying jobs to Ohioans and serve as the backbone of our economy.

[29] Direct Testimony of Stephen Baron p. 19.
[30] Public Radio International; DHL shuts down in Ohio (November 12, 2008)
[31] Cleveland Plain Dealer; Auto industry troubles leave UAW workers and suppliers struggling and worrying about bailout; by Frank Bentayou and Robert Schoenberger (November 13, 2008)

The Commission can improve the proposed rate mitigation plan to more reasonably apply the concepts of gradualism to the ESP rates in order to promote state policies, especially economic development. In a number of prior cases, the PUCO has cited the regulatory concept of gradualism in allocating increases to rate classes.[32]

OEG recommends that under a long-term plan the approved ESP revenue increases for non-shopping customers be allocated to retail rate schedules using the following three principles:[33]

1. Residential rates should reflect the increases suggested by the Companies (if the filed ESP rates are adopted) and not be charged any costs associated with rate mitigation under this plan. If alternative wholesale generation rates are approved, then residential rates should be adjusted accordingly to recover the residential class share of costs, without any additional mitigation charges produced under this plan.
2. No rate schedule should receive an increase greater than "2 Times" the retail average increase.
3. No rate schedule should receive a rate decrease if other schedules get an increase.

The Table below presents the results of the OEG Rate Mitigation Plan as applied to the FES offer.[34] This Table is for illustrative purposes only, as OEG believes that the FES generation supply proposal is not reasonable and should be rejected. This Table summarizes the 2009 (versus 2008) increases for each rate schedule under the FES offer.

[32] Re Toledo Edison Company, 168 P.U.R.4th 193, 1996 WL 190802, Case No. 94-1964-EL-CSS (1996); Re Columbia Gas of Ohio, Inc., 113 P.U.R.4th 1, 1990 WL 488733 (Ohio P.U.C.), Case No. 89-616-GA-AIR et al. (1990); Re Cincinnati Gas and Electric Company, 42 P.U.R.4th 252, Case Nos. 80-260-EL-AIR, 80-429-EL-ATA (1981).
[33] Direct Testimony of Stephen Baron p. 20.
[34] Direct Testimony of Stephen Baron, Baron Exhibit__(SJB-2).

OEG Mitigated Proposed Rate Increases Including Effect of Proposed Deferrals			
	2009 / 2008 Percentage Increases		
RATE CODE	OE	CE	TE
RS	2.38%	6.17%	5.73%
GS	5.31%	4.61%	4.74%
GP	8.18%	2.09%	0.96%
GSU	10.47%	1.60%	0.00%
GT	10.47%	9.24%	13.93%
POL	5.23%	9.24%	13.93%
STL	10.47%	9.24%	13.77%
TRF	10.47%	9.24%	0.00%
CONTRACTS		0.00%	
TOTAL COMPANY	5.23%	4.62%	6.96%

The mitigation should be accomplished via the charges and credits in the Companies' proposed Economic Development Rider ("EDR"). As stated in the Direct Testimony of Company witness Hussing at page 8, line 17, "[T]*he purpose of the Economic Development Rider is to promote gradualism and mitigate overall bill impacts to customers through a series of credits and charges…it is better to proactively address disproportionate rate impacts typically felt by those customers previously served on tariffs below average rates in order to promote economic stability*."[35] The OEG Mitigation Plan is consistent with this objective and OEG recommends that each Company's EDR be modified to incorporate the provisions of the OEG plan. In addition to the fact that the rationale for the OEG Rate Mitigation plan is to facilitate Ohio state policy, amounts charged to each rate schedule via the EDR should be non-bypassable, which will facilitate

[35] Hussing Direct at page 9, line 2.

the implementation of the mitigation plan and ensure that any revenue shortfalls are fully recovered by the Companies.[36]

OEG's plan moderates the full effect of wholesale cost increases to the industrial class by increasing the non-bypassable EDR charge on non-residential customers (primarily commercial customers). Industrial customers will have an incentive to remain on standard offer service. This will reduce POLR risks to the utilities. This will benefit all non-shopping customers by minimizing the retail risk premium that must be added to the wholesale generation price. Our proposal is revenue neutral to the Companies and has no effect on residential customers.

In the alternative, OEG believes that the rate spread recommendation of Nucor witness Dennis Goins for long-term ESP costs is also reasonable.[37] This proposal by Nucor is consistent with OEG's Rate Mitigation Plan.

If a new long-term supply arrangement with FES is not established before the end of 2008, then the Companies will have to purchase generation for non-shopping consumers through the MISO LMP market. If that procurement strategy is required, then the rate allocation method described in OEG's October 30, 2008 Short-Term ESP brief should be adopted.

[36] Direct Testimony of Stephen Baron p. 23.

[37] Mr. Goins' proposal is based on the Companies' "slice of the system" proposal in the 2007 CBP case. In that case, the Companies proposed a pricing mechanism that reflected the Commission's traditional recognition of the lower average cost of generation and transmission to serve higher load factor classes. Mr. Goins recommends that the Commission require the Companies to use this approach to set its class-specific ESP generation rates that can then be adjusted to reflect TOU and voltage differentials. Mr. Goins points out, and OEG agrees, that since the Companies recommended this approach in 2007, the Companies cannot now credibly argue that this approach is unreasonable for setting class-specific ESP generation rates. Mr. Goins explains: "*In its 2007 CBP case, FirstEnergy developed class allocation factors (CAFs) to convert the blended 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 historical average SSO rates for all classes. The CAFs by load class are shown in Table 2 below. These CAFs should be the first adjustment to FirstEnergy's proposed uniform ESP generation rate ($75 per MWh in 2009), followed by the TOU and voltage adjustments. If CAFs for additional classes are necessary, then FirstEnergy should be required to develop them consistent with the approach it used in 2007.*"

Mr. Goins proposed class allocation factors are taken directly from the Companies' proposal in the CBP case. They are: RS=1.000; GS=1.252; GP=0.900; GSU=0.800; GT=0.769 (Source: FirstEnergy 2007 CBP filing, Exhibit C2). The method is easy to implement. For example, assume that the Companies' uniform generation rate is $0.075 per kWh in 2009. For residential customers, the CAF-adjusted generation rate would be $0.075 per kWh (1.000 times $0.075 per kWh). Similarly, for GT transmission customers, the CAF-adjusted generation rate would be $0.0577 per kWh (0.769 times $0.075 per kWh). All CAF-adjusted rates would then be further adjusted using the TOU weights and voltage differentials developed by FirstEnergy. (Direct Testimony of Dennis Goins pp. 13-15)

The OEG Rate Mitigation Plan will produce statewide economic benefits by lowering industrial power rates. The rate increases associated with the proposed ESP would be particularly problematic for large industrial customers who must compete nationally and internationally for the sale of their products. It is less of a problem for business customers who compete locally.

For local competition, all customers pay the same electric rate and any subsidies built into those rates are competitively neutral. For example, Burger King and Wendy's compete with each other in the same neighborhood. As long as both pay the same electric rates neither is competitively disadvantaged. These businesses go where the people are. If a Burger King outlet closes there is a McDonalds waiting to take its place and there is no net job loss. Their success or failure is not affected by the price of electricity.

This is absolutely not the case for industrial manufacturers. Their products are sold nationally and internationally and their competitors are both domestic and foreign. When an auto manufacturing or steel plant closes, those jobs are likely gone forever. The market share that was served by the closed auto or steel plant is then absorbed by a manufacturer in another state or more likely another country. Unlike commercial customers, industrial customers in Ohio face national and international competition. Therefore, growing and maintaining industrial operations through reasonable electric rates is essential to achieve SB 221's policy goal to *"facilitate the state's effectiveness in the global economy."*[38]

[38] Direct Testimony of Stephen Baron p. 24.

4. THE COMMISSION SHOULD MAKE THE COMPANIES' \$10/MWH MINIMUM DEFAULT SERVICE CHARGE ("MDS") BYPASSABLE FOR SHOPPING CUSTOMERS THAT AGREE TO NOT TAKE SERVICE UNDER THE ESP DURING ITS THREE-YEAR TERM AND FOR CUSTOMERS WHO AGREE NOT TO SHOP DURING THE ESP.

As described by Companies' witness Kevin Warvell on page 8 of his Direct Testimony, the Companies have incorporated a 1 cent per kWh (\$10/mWh) charge in the base generation rates of each Company to provide compensation to the Companies due to their obligations to provide POLR service to customers who may switch to an alternative supplier during the term of the ESP. In particular, if the Companies procure generation for ESP load and a portion of this load elects to shop during the ESP (presumably due to lower market prices), the Companies would face excess capacity for which they would receive insufficient revenues. Alternatively, if more customers take POLR service than expected due to higher market prices, the Companies would be required to make market purchases at higher prices. To mitigate this market risk, according to Mr. Warvell, the Companies must purchase hedges.[39]

While the Companies have never submitted evidence or calculations justifying the amount of the charge and OEG questions its magnitude, it concedes that conceptually a POLR charge of some amount may be warranted. However, this POLR charge should be bypassable for ESP customers who either; a) agree to forego their right to shop during the three-year term of the ESP; or b) agree to not take service under the ESP and, in the event of a return to POLR service, agree to waive their right to take service under the ESP and accept market-based rates.

According to Mr. Warvell's testimony, the Companies have determined that \$10/mWh of the overall generation rate is associated with compensating the distribution utilities for shopping risk. If a customer, by election, agrees to either remain an ESP customer for the entire three-year plan term, or agrees to not take the ESP POLR generation rate during the three-year plan because the customer elects to shop

[39] Direct Testimony of Stephen Baron p. 25.

and further agrees to take market priced service in the event of a return to POLR service, the Companies would not incur any of the risks identified by Mr. Warvell in support of the $10/mWh minimum default service charge. At hearing Company witness Dr. Jones agreed with OEG Counsel that if a customer waives its right to shop for the remainder of the ESP term *"there aren't any shopping risks."*[40] Therefore, these customers should not be charged the $10/mWh. For customers agreeing to remain ESP customers for the entire three-year ESP term, the generation rate (Rider GEN) should be reduced by $10/mWh. For customers that shop and agree not to take the ESP POLR rate if they return to POLR service during the three-year period, the Companies' proposed Rider MDS should be waived.[41] This recommendation would apply regardless of the final structure of the Commission-approved ESP plan for the Companies.

5. THE TERMS OF THE ECONOMIC LOAD RESPONSE RIDER ("ELR") NEED TO BE MODIFIED.

The ELR rider offers existing standard tariff – interruptible and special contract – interruptible customers an option to receive additional interruptible credits if these customers agree to an unlimited number of economic interruptions. These economic interruptions would be triggered when the market price of power exceeds the ESP generation rate. At this point, customers would be permitted to buy-through the interruption at market prices. Effectively, if a customer elects the ELR rider, the customer would pay market-based rates when market prices exceed the ESP generation rate and otherwise pay the ESP generation rate.[42] While OEG supports the ELR rider and its goals of rate mitigation, the terms of the rider are not reasonable and would likely result in customers foregoing the rider, thus preventing potential benefits to these customers and to the Companies' firm customers from being achieved. OEG recommends several changes to the proposed ELR rider.

[40] TR Vol. III, p. 121 lines 12-24.
[41] Direct Testimony of Stephen Baron pp. 26-27.
[42] Direct Testimony of Stephen Baron p. 28.

First, the Companies' July 2007 Application to Establish a Competitive Bidding Process ("CBP", Case No. 07-796-EL-ATA), contained a proposal *similar to the* ELR *rider, yet* one with more reasonable terms.[43] The Companies' 2007 CBP Economic Load Response Program ("LRP") was different from the ELR in two very important ways. The first difference is that economic interruptions would only be called in the event that the day-ahead locational marginal price ("LMP") exceeded 125% of the competitive bid price. This is in contrast to the Companies' ELR proposal which initiates an economic interruption in the event that the day-ahead LMP exceeds the ESP generation rate (GEN rider and GPI rider).[44] The second important difference is that the 2007 proposal limited the number of hours a customer could be interrupted in a given year. The current ELR proposal has no limitation on the maximum annual hours of economic interruption. For large industrial manufacturing customers it is important that a reasonable limitation be imposed on the Companies' ability to interrupt service. The ESP ELR proposal, with no limitation (effectively 8,760 hours limitation), is so risky for customers that it creates a barrier to participation.[45]

OEG recommends that the two terms discussed above be adopted for the ELR. These two modifications to the ELR are:

1. Economic interruptions will be invoked when the day-ahead LMP exceeds 125% of the ESP generation rate for three consecutive hours
2. Economic interruptions are limited to 250 hours annually.

The next modification to the proposed ELR rider relates to the proposed basic $1.95 per kW month interruptible credit to reflect the value of avoided capacity. The reasonableness of this proposal is undermined by Company witness Dr. Jones, who testified that the appropriate capacity cost for the Companies is $2.20 per kW month.[46] This cost, when adjusted by a 13.5% factor (as used by Dr. Jones in

[43] Direct Testimony of Stephen Baron p. 28.
[44] Direct Testimony of Stephen Baron p. 29.
[45] Direct Testimony of Stephen Baron p. 29.
[46] Direct Testimony of Dr. Jones p. 13.

his Exhibit 4) equates to a $2.50 per kW month interruptible credit.[47] However, Dr. Jones' testimony also understates the value of avoided capacity. OEG believes that the proposal of Nucor witness Dennis Goins with respect to the value of avoided capacity is the most reasonable. Mr. Goins recommended basing the emergency interruptible credit on the Department of Energy's recent avoided cost estimate of $75 per kW-year subject to an adjustment to reflect the fact the cost of new peaking generation has increased substantially in recent years. (The DOE report relies on a 2004 estimate), and despite potential transmission benefits, the DOE estimate does not include any avoided cost of transmission. Given these factors, Mr. Goins recommends that the emergency interruptible credit should be set around $91 per kW-year or $7.50 per kW-month.[48] OEG agrees.

The third modification to the proposed ELR rider relates to the Companies' proposed methodology to determine the amount of interruptible load each month that will receive an interruptible credit. The Companies have proposed to calculate the monthly interruptible credit on the basis of Realizable Curtailable Load ("RCL"), which is determined annually by the difference between a customer's firm load and its average hourly demand ("AHD") during the hours of noon to 6:00 pm during the months of June through August. Effectively, the RCL on which customers will receive interruptible credits is limited to a customer's <u>average</u> on-peak load (less firm load), rather than a customer's on-peak load (less firm load). Notwithstanding this calculation, customers are required to curtail down to their firm load during any hour required by the Companies, if they request either an emergency or economic interruption. To the extent that a customer has a peak load in the on-peak period that exceeds the customer's AHD (average on-peak load), the Companies are not providing compensation for this interruptible load.[49]

[47] Direct Testimony of Stephen Baron p. 30.
[48] Direct Testimony of Dennis Goins pp. 24-25.
[49] Direct Testimony of Stephen Baron pp. 30-31.

The RCL should instead be computed based on the difference between a customer's on-peak load (used for billing purposes) and its firm load. From a planning standpoint, a utility would be required to provide capacity sufficient to meet its firm load requirements. To the extent that an interruptible customer has an on-peak load that is subject to curtailment down to a firm load level, the customer should receive credit for the full amount of its load that is subject to curtailment.[50]

Finally, the Companies are proposing a Capacity Cost Adjustment Rider ("CCA") to recover the costs of additional required reserves during the months of May through September, in the event that the FES capacity available to the Companies is insufficient to provide such reserves. The costs associated with such purchases are to be recovered from POLR customers via a bypassable charge. Though OEG does not oppose the proposed rider as it would apply to firm POLR load, it is inappropriate to charge this capacity rider to interruptible load. The requirement to obtain sufficient annual planning reserves is an obligation of the Companies based on their firm load, not their interruptible load. As a result, it would be inappropriate to apply this charge to interruptible load, for which the Companies do not need to obtain planning reserves. In particular, pursuant to the FERC's Order on the MISO Resource Adequacy Proposal (Order in FERC Docket No. ER08-394-000, issued March 26, 2008), planning reserve requirements for MISO members will be based on Load Serving Entity peak loads, excluding "Load Modifying Resources." Interruptible load represents one of the designated Load Modifying Resources. The Companies will not be required to obtain planning reserves for interruptible load and therefore should not charge the CCA rider to interruptible customers.[51]

[50] Direct Testimony of Stephen Baron p. 31.
[51] Direct Testimony of Stephen Baron p. 32.

6. ENFORCEMENT OF THE SIGNIFICANTLY EXCESSIVE EARNINGS TEST.

The vigorous enforcement of the significantly excessive earnings test is another tool for the Commission to use to protect consumers and incentivize FirstEnergy to cooperate in wholesale generation pricing.

If an ESP is approved, the Commission is required to review the ESP after one year and determine if the adjustments resulted in "*excessive earnings*" as measured by whether "*the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate.*" (RC §4928.143(F)) If the Commission finds that the ESP adjustments did result in significantly excessive earnings, "*it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments.*" (Id.)

The Commission needs to address the methodology for this test in this proceeding. It cannot wait until 2010. Under Generally Accepted Accounting Principles ("GAAP"), the utilities are required to recognize a regulatory liability for any refunds that arise each year and that will be refunded to ratepayers prospectively in the following year.

First, the Commission must determine the methodology it will use to compute the rate of return on common equity threshold over which the Companies will be deemed to have significantly excessive earnings.

Second, the Commission must determine the methodology it will use to compute the utility's actual earned return on common equity for each review year. This step is necessary so that the actual earnings can be compared to the threshold established in the first step.

Third, if the Company's actual earnings are in excess of the threshold, then the difference, grossed-up for taxes on a revenue requirement basis, should be refunded to ratepayers in accordance with the requirements of the statute.[52]

a. Determination Of The Significantly Excessive Earnings Threshold

The testimony of OEG witness Charles King sets forth a method for determining the significantly excessive earnings threshold.[53] Mr. King 1) identified a peer group of comparable utilities and non-utility businesses; 2) adjusted the earned returns of each group to match the risks faced by the three FirstEnergy companies operating in Ohio; 3) averaged the utility and non-utility returns to derive a base line earned level of return; and 4) applied an adder that describes the margin over this base line equity return that should be allowed before the earnings are considered significantly excessive. These steps are discussed in greater detail below.

First, Mr. King identified utilities and non-utilities that are comparable to the FirstEnergy companies. Value Line's Datafile contains the names of all 62 U.S. publicly traded companies that Value Line classifies as electric utilities.[54] In order to focus on heavily regulated companies, all companies that derived more than 20 percent of their revenue from unregulated operations were excluded from the comparison group. This criterion reduced the total number of companies to 36. The average of the earned returns on equity for the 36 heavily regulated electric utilities in 2007 was 10.09 percent.[55]

The group of non-utility companies was compiled from a list of 5,688 companies found in the Value Line Datafile. This list was narrowed down by eliminating electric, gas and water utilities,

[52] Direct Testimony of Lane Kollen p. 24.
[53] See Direct Testimony of Charles King pp. 4-10.
[54] See Direct Testimony of Charles King, Exhibit No.__(CWK-1)
[55] Direct Testimony of Charles King, Schedule 2.

companies that have a ratio of gross plant to revenue that are not similar to the FirstEnergy companies, small companies which would have higher return requirements than utilities, all companies with gross plant less than $1 billion, and any companies for which Value Line had not calculated a beta. The final list came to 219 companies.[56]

The average return on year-end 2007 equity of the non-utility companies was 14.14 percent.[57] However, these returns on equity cannot be considered comparable to the three FirstEnergy Companies because these non-utility companies are far riskier. The second step in Mr. King's methodology is to adjust the earned returns of each group to match the risks faced by the three FirstEnergy Companies.

For this purpose, Mr. King used the "beta" measure as generated by Value Line. Beta is a measure of the co-variance of each stock with that of the overall stock market. The overall stock market's beta is 1.00. To the extent that beta is greater than 1.00, the stock displays greater volatility and higher risk than the market. Betas less than 1.00 indicate less volatility and lower risk. The beta reflects all forms of risk, so it is the one comprehensive measure of risk that is available for most traded stocks.[58]

The average beta for the comparable non-utility companies is 1.08, reflecting the fact that these companies are, on average, more risky than the average for the market.[59] In contrast the average beta of the electric utility comparison group is 0.91, indicating a lower level of risk than the non-utility group.[60] The average return for the 219 non-utility companies needs to be adjusted in order to reflect the much lower risk associated with utility distribution service. While there are many measures of the risk premium, there seems to be a consensus that measured over very long periods of time the risk premium

[56] Direct Testimony of Charles King Schedule 4 of Exhibit No.__(CWK-1).
[57] Direct Testimony of Charles King, Schedule 2.
[58] Direct Testimony of Charles King p. 7.
[59] Direct Testimony of Charles King, Schedule 4 of Exhibit No.__(CWK-1).
[60] Direct Testimony of Charles King, Column E of Schedule 3 of Exhibit No.__(CWK-1)

has averaged about seven percent. Mr. King applied the difference between the 1.09 beta of the non-utility group and the 0.91 beta of the utility group, which is 0.17, to the seven percentage point risk premium to derive an adjustment of 115 basis points, or 1.15 percent. A reduction of 1.15 percent to the average non-utility earned return of 14.14 percent yields a risk-adjusted return of 12.96 percent.[61]

The third step of Mr. King's methodology is to average the utility and non-utility returns in order to derive a base line earned level of return. This step is necessary in order to account for the financial risk differences among the three FirstEnergy Companies. They have surprisingly different equity proportions, with TE having very conservative 61.5 percent equity, OE slightly more risky with 59.1 percent equity, and CEI the most risky with only 49.0 percent equity.[62]

Mr. King adjusted both the utility and non-utility equity returns to recognize these differences in financial risk resulting from different capital structures.[63] They are:

- Toledo Edison 10.27%
- Ohio Edison 10.57%
- Cleveland Electric Illuminating 11.78%

The final step in Mr. King's methodology is to apply an adder that describes the margin over this base line equity return that should be allowed before the earnings are considered significantly excessive. Here, it is necessary for the Commission to exercise its own judgment because there is no objective, generally accepted measure of a "*significantly excessive return.*" OEG recommends the use of the adders that the FERC awards to encourage investment by utilities in major innovative transmission lines. FERC provides a 50 basis point adder for participation in Regional Transmission Organizations and another adder of up to 150 basis points as an incentive for investment. FERC apparently believes that that this 200 basis point adder provides such a high return that it is sufficient to encourage risky

[61] Direct Testimony of Charles King, pp. 7-8.
[62] Direct Testimony of Charles King, p. 8.
[63] Direct Testimony of Charles King Schedule 6 of Exhibit No.__(CWK-1),

investments in transmission lines that must traverse difficult terrain and encounter siting resistance. Anything more than this healthy 200 basis point adder would be significantly excessive.[64]

If we add 200 basis points to the base line returns on year-end equity, the thresholds of significantly excessive earnings are:[65]

- Toledo Edison 12.27%
- Ohio Edison 12.57%
- Cleveland Electric Illuminating 13.78%

These threshold numbers are merely illustrative of the results that are derived from the methodology that OEG recommends. The first application of the significantly excessive earnings test will be in 2010 and based on earned returns in 2009. It is almost certain that 2009 earnings will be negatively affected by the current recession, which will lower the significantly excessive earnings threshold.

b. <u>Calculation of the Utility's Actual Earnings.</u>

The Commission should compute the actual earned return on common equity for each annual period using the per books actual accounting earnings on common equity and the utility's year-end actual common equity balance, with limited ratemaking adjustments. The authorized ratemaking adjustments should be specified by the Commission in this proceeding and should be modified only

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[64] *OEG has not adopted the statistical confidence levels that the utilities' witnesses have recommended because the use of statistical* confidence ranges would limit any finding of excessive earnings to so few observations that the test would become a cipher. A 95 percent confidence interval would mean that only 2.5 percent of all observations in the sample company groups would be deemed to have excessive earnings. A 90 percent confidence interval would increase that proportion to five percent. These intervals virtually ensure that no Ohio utility would ever be found to have experienced significantly excessive earnings.

[65] Direct Testimony of Charles King, p. 9.

prospectively upon consideration of a request from the utility or other party to add or remove such adjustments.[66]

The list can be as extensive or limited as the Commission believes is necessary to ensure that rates are reasonable. At a minimum, the ratemaking adjustments should be consistent with the requirements and limitations on cost-based recoveries specified in §4928.143(B)(2). For example, only prudent fuel and purchased power expenses should be included. Also, at a minimum, the ratemaking adjustments that are reflected should be consistent with other Commission orders wherein there were specific disallowances of or directions relating to rate base, expense or rate of return amounts or components.[67]

The Commission also should include all revenues from off-system sales in the computation of earnings, just as it should include all prudent purchased power expenses. This is essential, even for the utilities in this proceeding, because revenues from surplus sales or derivative gains should be used to offset the prudent purchased power expenses and derivative losses that are incurred.

In addition, the Commission should remove the effects of any refunds in one year based on the significantly excessive earnings test for the prior year so that the refund is computed on a discrete annual basis for the prior year and does not influence the actual earnings for another year.

The statute requires an annual application of the significantly excessive earnings test. It does not allow averaging over a multi-year period or over multiple entities. The statute requires the application of the test "*following the end of each annual period of the plan.*" Also, the threshold for significantly

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[66] Direct Testimony of Lane Kollen p. 25.
[67] Direct Testimony of Lane Kollen p. 25.

excessive earnings must be determined each year because the underlying data necessarily will change each year, including the group of companies that will be considered comparable and their earnings.[68]

The earnings of each utility must be calculated separately. "*In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expense, or earnings of any affiliate or parent company.*" RC §4928.143(F).

Finally, the Commission should require the utilities to exclude the effects of fines and penalties, one-time writeoffs, costs and acquisition premiums related to mergers and acquisitions, and effects of mark-to-market accounting for derivative gains and losses.

In 2007, TE earned 18.8%, CEI earned 18.55% and OE earned 12.51% on a per books basis, assuming no ratemaking adjustments. Both TE and CEI would be over the significantly excessive earnings threshold for 2007 if the threshold is computed in the manner proposed by Mr. King and if it had been applicable for 2007.[69]

A 1% return on common equity is equivalent to approximately $8 million in increased revenues for TE, $27 million for OE and $26 million for CEI. Stated another way, if the Commission found that the utilities had excess earnings by 1%, then these are the amounts of refunds that would be required.[70]

c. **Refunds of Excessive Earnings.**

The statutory test suggests a limitation on the potential refunds by linking the excess earnings to the "adjustments" pursuant to any ESP. Subject to a correct understanding of the purpose of the test and

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[68] Direct Testimony of Lane Kollen pp. 33-34.
[69] Direct Testimony of Lane Kollen, Exhibit___(LK-13).
[70] Direct Testimony of Lane Kollen pp. 34-35.

the definition and application of the term "adjustments," the statute appears to limit potential refunds to the amount of the ESP increases recovered during the year subject to review. RC §4928.143(F) states:

> *"With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate."*

The total ESP rate increases or adjustments in any review year should be computed by multiplying the ESP riders by the actual billing determinants for the year. This yields the total ESP revenues in the review year. This annual dollar amount is the maximum amount of the utility's refund obligation during any review year of the ESP.[71]

Another interpretation would be to assume that the term "adjustments" refers both to ESP rate riders and to the specific incremental costs that justified the riders. Under this interpretation, the ESP rate increases and the incremental costs necessarily net to zero. There would be no effect on earnings and an ESP adjustment could never result in significantly excessive earnings. The Commission should reject this interpretation as inconsistent with the plain language of the statue and dismiss this interpretation under the long-held rule of statutory construction that provides that courts must construe the applicable statute in order to avoid unreasonable or absurd results. See, e.g., State ex rel. Leslie v. Ohio Hous. Fin. Agency, 105 Ohio St.3d 261 (2005); State ex rel. Gaydosh v. Twinsburg, 93 Ohio St.3d 576 (2001).

If the utilities' potential interpretation is adopted, there never could be any significantly excessive earnings. Their definition of the term "adjustments" to mean both ESP rate increases and the

[71] Direct Testimony of Lane Kollen p. 31.

costs used to justify the increases would preclude any net effect on earnings. If this potential interpretation is adopted, the earnings test is vitiated and meaningless and there would be no meaningful ratepayer protection against excessive rate increases. Obviously the Legislature would not have included the significantly excessive earnings test in SB 221 if they intended it to be meaningless and offer no protection to consumers.[72]

If a refund is ordered, a gross-up for income taxes is necessary because the earnings are stated on an after tax basis, not on a before tax revenue basis. Such a gross-up for income taxes is similar to the historic use by the Commission of a gross revenue conversion factor to convert operating income deficiencies or surpluses into revenue deficiencies or surpluses. The objective is to determine the amount of revenue over-collections in the prior year that resulted in the significantly excessive earnings so that an equivalent amount can be refunded to ratepayers.[73]

7. THE COMPANIES' RECOMMENDED INTERPRETATION OF THE EXCESSIVE EARNINGS TEST IS INAPPROPRIATE.

The Companies' characterization of the excessive earnings test would dull it to the point that the test would cease to provide any protection to Ohio consumers. Company witness Mr. Vilbert states that the purpose of the test is "*to identify significantly excessive, windfall profits*" and that all "*extraordinary or nonrecurring items, or* [profits that] *are otherwise non-representative of the utility's operations*" should be excluded from the computation of earnings for the purpose of the test. (Vilbert Direct at 9). The obvious intention of this recommendation is to understate the Companies' level of earnings.

SB 221 does not specify the methodology the Commission should use to compute the utility's actual earnings. However, the Commission should not blindly exclude all gains or nonrecurring items

[72] Direct Testimony of Lane Kollen p. 32.
[73] Direct Testimony of Lane Kollen p. 29.

from the computation of the earned return. Instead, the Commission should establish the methodology as recommended by OEG above and carefully prescribe the income or losses that should be excluded from the c+omputation, if any.

Mr. Vilbert proposes that the Commission exclude the after tax earnings effects on CEI's proposed write-off of RTC and extended RTC, net of revenue credits, by adding back this amount to CEI's per books common equity outstanding for the significantly excessive earnings test. This is reasonable in concept, but the Commission should impose limitations on the amount and duration of the adjustment so that it does not become a permanent addition to common equity long after the utility has rebalanced its capital structure to targeted levels. It would be reasonable to assume that the utility will rebalance its capital structure within three years or by the end of the initial three year term of the ESP. Thus, the Commission should allow an adjustment to common equity on a declining basis reflecting a three year amortization of the write-off effects. For 2009, the adjustment would be 2/3 of the after tax write-off, assuming a year-end common equity balance. For 2010, the adjustment would be 1/3 of the after tax write-off. For 2011 and beyond, there would be no further adjustments.[74]

The Companies also propose that the Commission exclude the revenues from the proposed Delivery Service Improvement rider from the computation of after tax earnings for the significantly excessive earnings test. The Commission should reject this proposal for several reasons:

First, SB 221 contemplates no such ad hoc exclusions to the "adjustments" resulting from the ESP. Revenues from the Delivery Service Improvement are estimated to be $112.9 million per year.[75]

[74] Direct Testimony of Lane Kollen p. 27.
[75] TE Vol. IV, p. 163 (Hussing).

Removal of $112.9 million in revenue would result in a distorted picture of the utilities' financial condition.[76]

Second, the inclusion of these revenues in the test in no way removes the incentive aspect of this proposed rider. The distribution utilities have an independent obligation to provide reliable distribution service under either an MRO or ESP. A distribution infrastructure improvement surcharge is explicitly authorized in an ESP but not an MRO. The ability to get real time recovery through an ESP surcharge (rather than through a traditional rate case with its associated regulatory lag) provides incentive to make the required investments, even if excess profits generated by the surcharge are subject to refund.[77]

Third, the Companies' claim that this $112.9 million should be excluded based on the requirement that the Commission consider "*the capital requirements of future committed investments in this state*" (RC §4928.143(F)) is in error. Distribution system improvements are a normal and recurring cost of providing utility service. There is nothing extraordinary about it. If the utilities commit to a multi-billion dollar base load generating plant then this provision may have application, but they have not. There is no provision that allows the revenues for normal capital additions to be ignored in computing the utility's actual rate of return.[78]

[76] Direct Testimony of Lane Kollen p. 28.
[77] Direct Testimony of Lane Kollen p. 28.
[78] Direct Testimony of Lane Kollen pp. 28-29.

III. CONCLUSION

OEG worked long and hard with the Strickland Administration, the Ohio Manufacturers' Association, the Ohio Coalition for Affordable Power and other stakeholders to achieve the passage of SB 221. SB 221 reimposes a form of cost-of-service ratemaking through the regulation of utility earnings. This new regulatory structure should result in reasonable rates for consumers who do not shop, especially for the ratepayers of the utilities that still own generation (AEP, Duke, DP&L). We always knew that FirstEnergy would be different. Because the FirstEnergy utilities do not own generation the Commission's job is more complicated.

The recent severe economic downturn has created at least one silver lining. The current recession has resulted in a significant decline in the wholesale market price of electricity. The wholesale market price for generation has declined by at least 24% since the Companies' ESP offer of $75/mWh in 2009, $80/mWh in 2010, and $85/mWh in 2011 (plus additional riders for fuel, fuel transportation, environmental costs, and other costs)was made on July 31, 2008. Because the July 31, 2008 ESP generation offer price is above current market pricing, it is not more favorable in the aggregate than an MRO, represents an imprudent purchase by the utilities, and does not result in reasonable rates. Here is the modified ESP structure that we believe is most in the public interest.

1. If FES refuses to lower its pricing to reflect current market conditions, then the Commission should order Ohio Edison, Toledo Edison and Cleveland Electric Illuminating to procure electricity for non-shoppers through a least-cost portfolio of generation products. In the short term, there should be reliance on the MISO day-ahead spot market, with hedging as appropriate. There is a high likelihood that such pricing would be below $75/mWh – $85/mWh (plus adders). This procurement strategy would also incentivize FES to negotiate.

2. Once a reasonable wholesale power supply arrangement is established, the Commission must allocate and design those wholesale costs into retail rates.

If a long-term arrangement with FES is ultimately agreed upon, then OEG's rate mitigation plan should be adopted. This rate mitigation plan will reduce rate shock by limiting the rate increase to any customer class to two-times the system average increase. OEG's rate mitigation plan is revenue neutral to the utilities and has no effect on residential consumers. Our plan promotes economic development by limiting industrial rate increases through a non-bypassable charge on other business customers.

If a short-term procurement strategy through the MISO market is required, then the rate allocation method described in OEG's October 30, 2008 Short-Term ESP brief should be adopted.

3. Shopping options should be maintained. The $10/mWh minimum default service charge proposed by the utilities is especially egregious and should be eliminated. No justification for this POLR charge has been presented.

4. The interruptible program offered by the utilities should be enhanced. This program is especially appropriate given the economic slowdown and reduced industrial operations.

5. The standards for implementing the significantly excessive earning test should be clearly set out. The vigorous application of the earnings test can be used to incentivize FirstEnergy to cooperate with the Commission.

We appreciate that the Commission is under a great deal of pressure. But so is FirstEnergy. We urge the Commission to be aggressive. Having divested its generation and opted for market pricing, FirstEnergy cannot reasonably expect to be immune from the dramatic fall in the wholesale power market.

Respectfully submitted,

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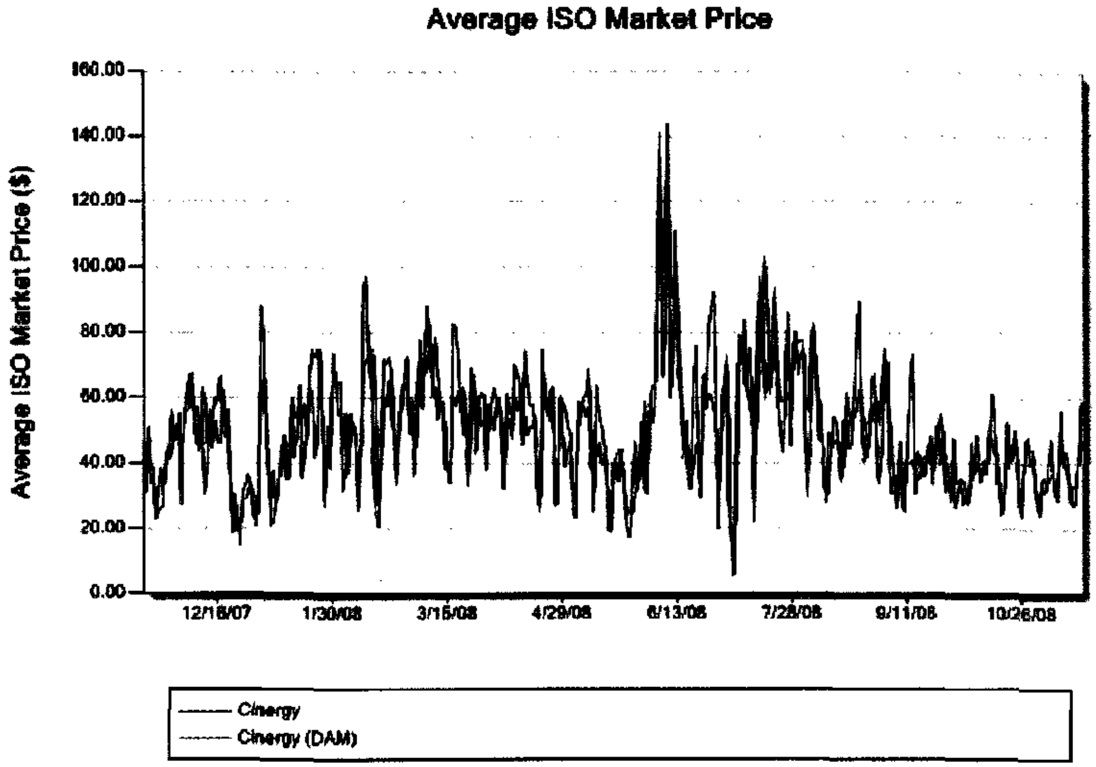
COUNSEL FOR THE OHIO ENERGY GROUP

November 21, 2008

SNL*i*

SNLFinancial

ISO Market Pricing Graph



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Attachment A

SNL*i*

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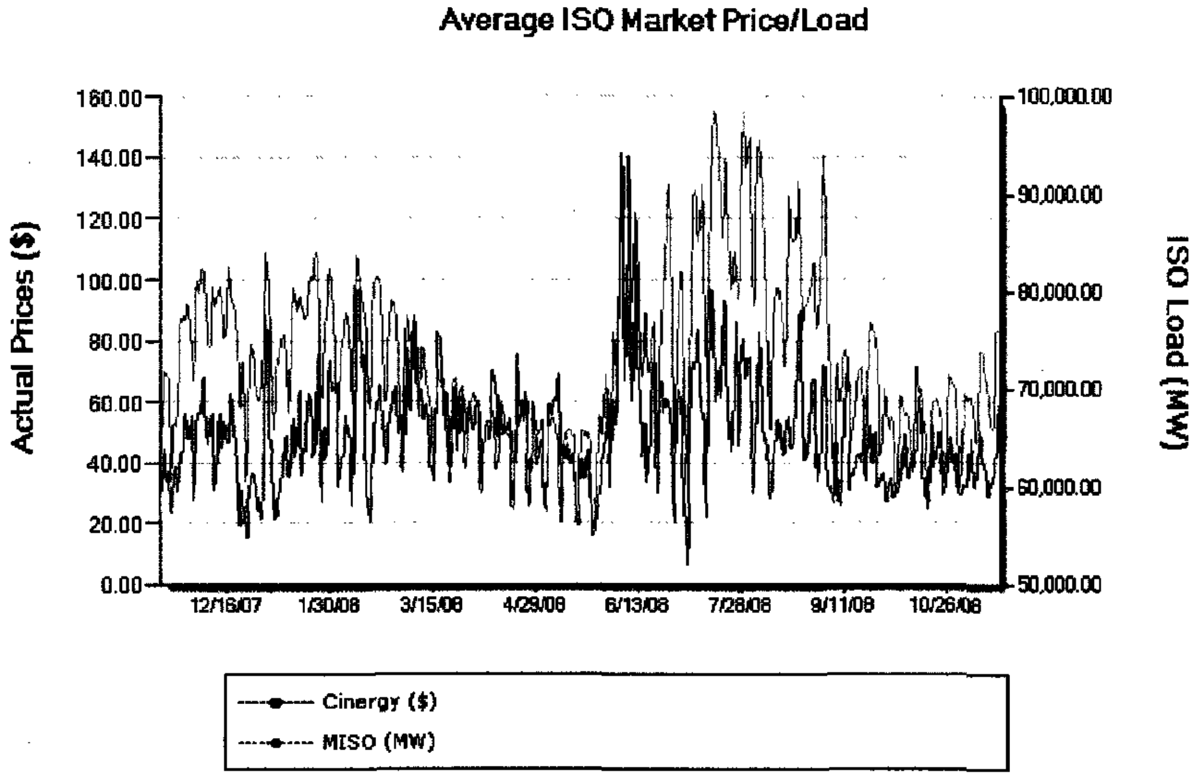
ISO Market Pricing Graph



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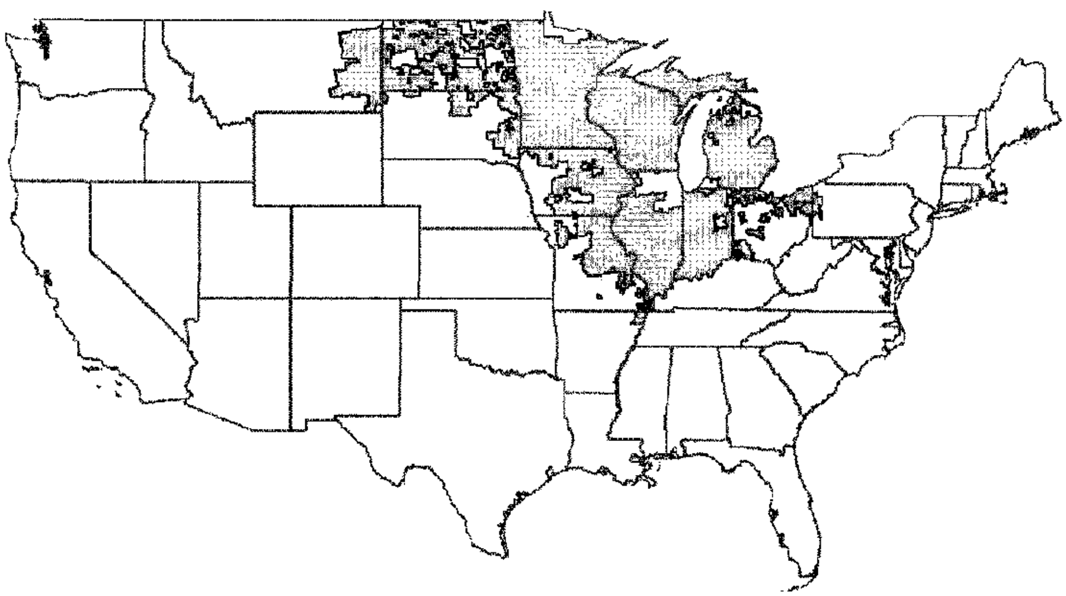
Attachment B

Attachment C

MidwestISO
Energizing the Heartland

Midwest Independent System Operator

2008-2009 Winter Reliability Assessment



Midwest ISO Market Footprint

Regulatory and Economic Studies (RES) Department

Attachment C

Table of Contents

1. Executive Summary

The Midwest ISO reserve margin for the 2008-2009 winter period is 42.0% which exceeds the minimum reserve requirements established by the States and Planning Reserve Sharing Groups. A slowing economy triggered a stagnant forecasted demand. An increase in demand side resources and footprint capacity, primarily renewables, resulted in projected risk levels remaining at or below the levels experienced during the 2007-2008 winter period.

The Midwest ISO is a Regional Transmission Organization (RTO) that coordinates operation of transmission facilities in 15 states and one Canadian province. Under the North American Electric Reliability Corporation (NERC), Midwest ISO functions as the Reliability Authority (RA) for utilities in the region. Midwest ISO runs a price-driven electricity market in which Locational Marginal Pricing, or LMP, provides price transparency for users of the wholesale bulk electric system. As such, Midwest ISO has a filed Transmission and Energy Market Tariff at the Federal Electric Regulatory Commission. Approximately 83% of the load in the Midwest ISO RA footprint is in the Market. Resources used to meet this load include internal generators, external purchases, Interruptible Load (IL), and Direct Controlled Load Management (DCLM).

This document assesses the sufficiency levels across the Midwest ISO Market during the 2008-2009 winter peak. The Midwest ISO currently does not establish reserve margins for member Load Serving Entities. Instead, reserve margins are established by State Authorities and Planning Reserve Sharing Groups to provide an adequate level of reliability. It can be determined that when the reserve requirements of the States and Planning Reserve Sharing Groups have been satisfied, the Midwest ISO can be considered to have sufficient resources.

A slowing economy joined with an increase in the amount of demand response programs resulted in an approximate 1.76% decrease in the expected peak demand for the 2008-2009 winter when compared to 2007-2008 forecast – 3.72% decrease from the 2007-2008 actual winter peak. As evident in Table 1-1 the expected coincident net demand for the 2008-2009 winter is 79,362 MW. The forecasted net demand level assumes full utilization of demand response programs; a condition which would not likely occur unless a Maximum Generation Event (EOP-002) was declared. There are 112,728 MW of resources that have an obligation to exclusively serve Midwest ISO load during peak conditions; 5,562 MW of these resources originate outside of the Midwest ISO Market. In an effort to meet renewable mandates, the amount of wind generation (based on nameplate capacity – the manufacturer's rating) within the Midwest ISO has almost doubled relative to the 2007-2008 winter. The projected reserve margin for the 2008-2009 winter is 33,366 MW or 42.0% of the coincident net internal demand, which exceeds the State Authorities' and Planning Reserve Sharing Groups' established minimum requirement of 11,507 MW or 14.5%.

Demand (MW)	'08-'09	'07-'08
Non-Coincident	88,313	88,321
Estimated Diversity	2,374	2,374
Gross Coincident	85,939	85,947
Direct Control Load Management	559	134
Interruptible Load	2,624	1,958
Behind-the-Meter Generation	3,394	3,071
Net Internal Demand	***79,362***	***80,784***
Capacity (MW)	**'08-'09**	**'07-'08**
Internal Designated Network Resources	107,076	98,710 [1]
External Designated Network Resources	5,652	5,999
Adjusted Resources	***112,728***	***104,709***
NERC Construct Reserve Margin	**'08-'09**	**'07-'08**
Reserve Margin (MW)	33,366	23,925
Reserve Margin (%)	42.0%	29.6%

[1] In 2008, former ECAR members went from a 4% Operating Reserve Requirement to a 12% - 14.3% Planning Reserve Requirement

Table 1-1: Midwest ISO Winter 2008-2009 and 2007-2008 Load and Capability

This assessment uses probabilistic methods to analyze the effect of various conditions on the Loss of Load Expectation (LOLE). Conditions under analysis include load forecast uncertainty, forced outage rate, and capacity derates. This analysis was performed on 27 combinations of load, generator commitments, and system forced outage rates using an unconstrained transmission system model over the three winter months.

Loss of Load Expectation analysis was performed and results indicate that no significant Loss of Load events are expected. This is consistent with previous year long studies that show peak risk during the summer season. While no Loss of Load Expectation was determined for any case, not all eventualities can be modeled. In the event that system conditions should exceed the levels modeled within this analysis, these results would no longer speak to the risk experienced by the system. Due to the unconstrained nature of this simulation it is still possible that transmission constraints experienced through the winter months could limit power imports to certain regions and put those regions at risk.

It is always possible that a combination of high loads due to adverse weather coupled with a high rate of outages and lack of external support could result in curtailment of firm demand. Such a curtailment is considered to be a low probability event for this winter, since the projected reserve margin is above the Planning Reserve Sharing Groups' and States Authorities' established minimum requirement, Loss of Load Expectation analysis indicates that no significant Loss of Load events are expected, and fuel scarcity is not projected to be an issue.

Attachment D

SNLi SNLFinancial

NYMEX Natural Gas Futures

For graphs and historical data, click on the links below.
11/18/2008

Contract	Prior Settle ($/mmBtu)	High ($/mmBtu)	Low ($/mmBtu)	Settle ($/mmBtu)	Change ($/mmBtu)	Volume
Prompt Month	6.533	6.700	6.440	6.516	-.017	-
Dec-2008	6.533	6.700	6.440	6.516	-.017	-
Jan-2009	6.641	6.740	6.580	6.602	-.039	-
Feb-2009	6.701	-	-	6.662	-.039	-
Mar-2009	6.691	-	-	6.660	-.031	-
Apr-2009	6.681	6.665	6.585	6.640	-.041	-
May-2009	6.748	6.790	6.790	6.707	-.041	-
Jun-2009	6.866	6.915	6.915	6.829	-.037	-
Jul-2009	6.996	7.040	7.030	6.961	-.035	-
Aug-2009	7.086	7.125	7.125	7.053	-.033	-
Sep-2009	7.126	7.165	7.165	7.095	-.031	-
Oct-2009	7.211	7.270	7.235	7.180	-.031	-
Nov-2009	7.566	-	-	7.535	-.031	-
Dec-2009	7.951	-	-	7.920	-.031	-
Jan-2010	8.196	-	-	8.165	-.031	-
Feb-2010	8.201	-	-	8.170	-.031	-
Mar-2010	8.026	-	-	7.995	-.031	-
Apr-2010	7.461	-	-	7.425	-.036	-
May-2010	7.431	-	-	7.395	-.036	-
Jun-2010	7.526	-	-	7.490	-.036	-
Jul-2010	7.636	-	-	7.595	-.041	-
Aug-2010	7.716	-	-	7.675	-.041	-
Sep-2010	7.746	-	-	7.705	-.041	-
Oct-2010	7.826	-	-	7.785	-.041	-
Nov-2010	8.093	-	-	8.050	-.043	-
Dec-2010	8.431	8.431	8.431	8.385	-.046	-
Jan-2011	8.661	8.663	8.663	8.615	-.046	-
Feb-2011	8.646	-	-	8.595	-.051	-
Mar-2011	8.406	-	-	8.355	-.051	-
Apr-2011	7.681	-	-	7.640	-.041	-
May-2011	7.601	-	-	7.555	-.046	-
Jun-2011	7.681	-	-	7.635	-.046	-
Jul-2011	7.781	-	-	7.730	-.051	-
Aug-2011	7.861	-	-	7.810	-.051	-
Sep-2011	7.891	-	-	7.840	-.051	-
Oct-2011	7.971	-	-	7.920	-.051	-
Nov-2011	8.211	-	-	8.155	-.056	-
Dec-2011	8.476	-	-	8.425	-.051	-
Jan-2012	8.696	-	-	8.640	-.056	-
Feb-2012	8.681	-	-	8.620	-.061	-
Mar-2012	8.436	-	-	8.375	-.061	-
Apr-2012	7.666	-	-	7.605	-.061	-
May-2012	7.581	-	-	7.520	-.061	-
Jun-2012	7.656	-	-	7.595	-.061	-
Jul-2012	7.751	-	-	7.690	-.061	-
Aug-2012	7.826	-	-	7.765	-.061	-
Sep-2012	7.856	-	-	7.795	-.061	-
Oct-2012	7.936	-	-	7.875	-.061	-
Nov-2012	8.176	-	-	8.115	-.061	-
Dec-2012	8.441	-	-	8.380	-.061	-
Jan-2013	8.666	-	-	8.600	-.066	-
Feb-2013	8.651	-	-	8.585	-.066	-
Mar-2013	8.411	-	-	8.345	-.066	-
Apr-2013	7.641	7.660	7.660	7.575	-.066	-
May-2013	7.571	-	-	7.505	-.066	-
Jun-2013	7.656	-	-	7.590	-.066	-

Jul-2013	7.751	-	-	7.685	-.066	-
Aug-2013	7.826	-	-	7.760	-.066	-
Sep-2013	7.856	-	-	7.790	-.066	-
Oct-2013	7.936	-	-	7.870	-.066	-
Nov-2013	8.196	-	-	8.135	-.061	-
Dec-2013	8.486	-	-	8.430	-.056	-
Jan-2014	8.716	-	-	8.650	-.066	-
Feb-2014	8.701	-	-	8.635	-.066	-
Mar-2014	8.471	-	-	8.405	-.066	-
Apr-2014	7.691	7.790	7.790	7.625	-.066	-
May-2014	7.641	-	-	7.575	-.066	-
Jun-2014	7.721	-	-	7.655	-.066	-
Jul-2014	7.816	-	-	7.750	-.066	-
Aug-2014	7.881	-	-	7.815	-.066	-
Sep-2014	7.916	-	-	7.850	-.066	-
Oct-2014	8.001	-	-	7.935	-.066	-
Nov-2014	8.261	-	-	8.195	-.066	-
Dec-2014	8.591	-	-	8.525	-.066	-
Jan-2015	8.826	-	-	8.760	-.066	-
Feb-2015	8.821	-	-	8.755	-.066	-
Mar-2015	8.596	-	-	8.530	-.066	-
Apr-2015	7.856	7.900	7.900	7.790	-.066	-
May-2015	7.826	-	-	7.760	-.066	-
Jun-2015	7.906	-	-	7.840	-.066	-
Jul-2015	8.001	-	-	7.935	-.066	-
Aug-2015	8.071	-	-	8.005	-.066	-
Sep-2015	8.101	-	-	8.035	-.066	-
Oct-2015	8.181	-	-	8.115	-.066	-
Nov-2015	8.461	-	-	8.395	-.066	-
Dec-2015	8.791	-	-	8.725	-.066	-
Jan-2016	9.011	-	-	8.945	-.066	-
Feb-2016	9.001	-	-	8.935	-.066	-
Mar-2016	8.781	-	-	8.715	-.066	-
Apr-2016	8.011	-	-	7.945	-.066	-
May-2016	7.991	-	-	7.925	-.066	-
Jun-2016	8.071	-	-	8.005	-.066	-
Jul-2016	8.161	-	-	8.095	-.066	-
Aug-2016	8.216	-	-	8.150	-.066	-
Sep-2016	8.236	-	-	8.170	-.066	-
Oct-2016	8.316	-	-	8.250	-.066	-
Nov-2016	8.611	-	-	8.545	-.066	-
Dec-2016	8.951	-	-	8.885	-.066	-
Jan-2017	9.176	-	-	9.110	-.066	-
Feb-2017	9.166	-	-	9.100	-.066	-
Mar-2017	8.946	-	-	8.880	-.066	-
Apr-2017	8.166	-	-	8.100	-.066	-
May-2017	8.146	-	-	8.080	-.066	-
Jun-2017	8.226	-	-	8.160	-.066	-
Jul-2017	8.316	-	-	8.250	-.066	-
Aug-2017	8.376	-	-	8.310	-.066	-
Sep-2017	8.396	-	-	8.330	-.066	-
Oct-2017	8.476	-	-	8.410	-.066	-
Nov-2017	8.786	-	-	8.720	-.066	-
Dec-2017	9.136	-	-	9.070	-.066	-
Jan-2018	9.376	-	-	9.310	-.066	-
Feb-2018	9.361	-	-	9.295	-.066	-
Mar-2018	9.131	-	-	9.065	-.066	-
Apr-2018	8.331	-	-	8.265	-.066	-
May-2018	8.316	-	-	8.250	-.066	-
Jun-2018	8.396	-	-	8.330	-.066	-
Jul-2018	8.486	-	-	8.420	-.066	-
Aug-2018	8.546	-	-	8.480	-.066	-
Sep-2018	8.566	-	-	8.500	-.066	-
Oct-2018	8.656	-	-	8.590	-.066	-
Nov-2018	8.966	-	-	8.900	-.066	-
Dec-2018	9.316	-	-	9.250	-.066	-
Jan-2019	9.556	-	-	9.490	-.066	-

Feb-2019	9.541	-	-	9.475	-.066	-
Mar-2019	9.311	-	-	9.245	-.066	-
Apr-2019	8.491	-	-	8.425	-.066	-
May-2019	8.476	-	-	8.410	-.066	-
Jun-2019	8.556	-	-	8.490	-.066	-
Jul-2019	8.646	-	-	8.580	-.066	-
Aug-2019	8.706	-	-	8.640	-.066	-
Sep-2019	8.726	-	-	8.660	-.066	-
Oct-2019	8.816	-	-	8.750	-.066	-
Nov-2019	9.126	-	-	9.060	-.066	-
Dec-2019	9.496	-	-	9.430	-.066	-
Jan-2020	9.736	-	-	9.670	-.066	-
Feb-2020	9.721	-	-	9.655	-.066	-
Mar-2020	9.491	-	-	9.425	-.066	-
Apr-2020	8.661	-	-	8.595	-.066	-
May-2020	8.646	-	-	8.580	-.066	-
Jun-2020	8.726	-	-	8.660	-.066	-
Jul-2020	8.816	-	-	8.750	-.066	-
Aug-2020	8.866	-	-	8.800	-.066	-
Sep-2020	8.886	-	-	8.820	-.066	-
Oct-2020	8.976	-	-	8.910	-.066	-
Nov-2020	9.296	-	-	9.230	-.066	-
Dec-2020	9.686	-	-	9.620	-.066	-

Changes in settlement price with zero volume mean the settlement price is implied. No actual trading took place for these contracts on the given day. Price is based on delivery at the Henry Hub in Louisiana, which serves markets throughout the US East Coast, the Gulf Coast, the Midwest, and up to the Canadian border.